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IEAGHG

CO_2 Transport and Storage Cost Review

Technical Report 2025-08
October 2025

IEAGHG

About the IEAGHG

IEAGHG are at the forefront of cutting-edge carbon, capture and storage (CCS) research. We advance technology that reduces carbon emissions and accelerates the deployment of CCS projects by improving processes, reducing costs, and overcoming barriers. Our authoritative research is peer-reviewed and widely used by governments and industry worldwide. As CCS technology specialists, we regularly input to organisations such as the IPCC and UNFCCC, contributing to the global net-zero transition.

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To ensure the quality and technical integrity of the research undertaken by IEAGHG each study is managed by an appointed IEAGHG manager. The report is also reviewed by a panel of independent technical experts prior to its release.

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Report Overview:

CO_2 Transport and Storage Cost Review

Introduction

The objective of the study was to review publicly available information on CO_2 transport and storage (T&S) costs, to provide insights into how typical cost estimates are built up and to inform on areas of risk. Current information on T&S costs and the need for new or improved data would be explored.

Key Messages

- **Transport Distance Impacts Cost.** The distance between CO_2 emitters and storage sites significantly influences both capital and operational costs. Longer distances require more extensive pipeline infrastructure or shipping solutions, increasing overall system complexity and expense.
- **Emitter Type and System Utilisation.** Understanding the types of emitters early in project design is critical to estimating system utilisation and forecasting both capital and operating costs throughout the project lifecycle.
- **Economies of Scale in Pipelines.** Pipeline-based transport systems offer substantial economies of scale. Incremental capacity can be added at relatively low cost if considered during the initial design phase.

- **Shipping Costs Depend on Location and Volume.** Shipping costs are closely tied to emitter-to-store distance and shipment volumes. Failing to account for these variables can lead to inaccurate cost assessments and suboptimal system design.
- **Number of Storage Sites Affects Capital Expenditure.** Systems requiring multiple storage sites to meet long-term capacity needs typically incur higher capital expenditure than those relying on fewer, larger-capacity stores.
- **Storage Integrity and Legacy Well Risk.** Ensuring the integrity of a CO_2 storage site is critical for both containment and long-term project success. Careful site selection, robust storage design and ongoing monitoring are key to identifying and addressing potential issues early, enabling timely and effective remediation if needed. Legacy wells can pose a significant leakage risk; however, this risk can be effectively managed through comprehensive site evaluation and targeted risk mitigation strategies. A strong focus on risk management not only enhances storage security but also supports more accurate and reliable cost forecasting.
- **System Design Driven by Key Variables.** The design of T&S systems is shaped by emitter location, storage site characteristics and initial reservoir pressure. A clear understanding of these factors is vital for managing lifecycle costs and optimising system performance.
- **Monitoring and Regulatory Compliance Costs.** Measurement, monitoring, and verification (MMV) are core regulatory requirements to ensure long-term storage performance and environmental safety. MMV strategies and associated costs vary by site and jurisdiction but can represent a significant portion of overall storage costs.

Motivation and Scope

Recent climate commitments and government policies are accelerating the development of carbon capture and storage (CCS) projects globally. Internationally recognised as an essential component of the portfolio of technologies to achieve net-zero emissions, there is heightened interest in CCS with an increasing number of regions considering deployment of the technology at scale.

The cost of CCS has been a topic of investigation in both the public and private sectors for decades. Given the urgency of addressing climate change, the number of CCS projects that have been constructed and are operational is relatively low. In March 2023, there were 43 CCS plants in operation, capturing around 50 Mt CO_2. With more than 500 plants globally at various stages of development and construction, however, the pace of deployment is rising.

Developing cost estimates for large-scale investment decisions is an expensive process, often requiring tens to hundreds of millions of pounds to fully understand project costs and benefits. To avoid wasted effort and expenditure on stalled or halted projects, many developers use a gated approach to investment decision-making. In the early stages of project development, using costs of similar operational projects is a common method to determine the viability of the business case at a high level. This approach helps screen out poor-value projects and avoids inefficient spending on development costs. It can also help stakeholders to compare the value of proposed projects later in the project cycle once bespoke project costs are more developed or as government policies develop on the topic.

Much of the publicly available information on CCS costs focuses on a small number of projects, such as Petra Nova, Boundary Dam, Northern Lights and Quest, or are from academic studies. There is a lack of diverse information on the costs of capturing, transporting and storing CO_2. The relative lack of reliable high-level and more detailed cost benchmark data is posing challenges for stakeholders when making decisions on CCS project investments.

To address these challenges in part, a study was proposed to review public information on CCS T&S costs, to provide insights into how typical cost estimates are built up and to inform on areas of risk.

Given a lack of confidence in the availability of good data or estimates of T&S costs, a two-phase approach was proposed. Phase 1 (this study) would summarise current information on T&S costs, the major sources, and the need for new or improved data. Based on the merits, scope, feasibility and cost of continuing, sufficient information would be available for a decision on progressing to a Phase 2, which would aim to collect new data and/or develop new/improved modelling capabilities to address the highest priority areas and data gaps identified in Phase 1.

Conclusions

This review confirms the initial premise of the study, i.e., that there are limited publicly available sources of recent and useful cost information published. The information that is available shows a wide range, which would be expected given the different locations and project archetypes in the published data.

At an appropriate time in the project lifecycle, an informed user of the published cost information may be able to interpret the data and use it in an appropriate manner to inform decisions being made on projects, policy, or investments. Understanding the technical and commercial aspects of a given project allows the informed user of the data to narrow down the range of costs, albeit from a small data set and reduce the potential for misunderstandings of cost.

However, the published cost information suffers from a lack of clarity on the underlying assumptions that drive the estimates. This issue is to be expected given the relative complexity of the systems, the confidential nature of some of the important variables, and the general uncertainty of key items such as project lifetime capacity utilisation. This issue does significantly increase the risk of inappropriate cost data being used as either a benchmark or to set policy. Even well-informed users of the data may fall foul of this issue because of the complexity of the problem, and it would be unsurprising if mistakes have been made previously where this data has been used.

The issues described above can be mitigated by developing a standard reporting framework for costs and by using a standard project process to develop those costs. It is thought that this solution to the problem could be easily implemented in conjunction with stakeholders by combining existing similar processes used extensively in industry and forms one of the key recommendations from this work. In addition to the standardised reporting metrics and processes, developing a T&S specific cost estimating database for common equipment, in collaboration with developers, could be advantageous. Industry-wide benchmarking databases already exist for oil and gas projects and have been utilised by industry for an extended period. The use of benchmarking databases for oil and gas projects suggests that developing a similar resource for CCS projects would be both useful and feasible. It is known that developers and existing providers of benchmarking services are already developing CCS-specific cost databases and there may be benefits in IEAGHG members focusing on and investing in one of the existing databases for this purpose.

Additional recommendations are provided to help to improve Capex and Opex estimates for individual projects. These tools and frameworks are already in use within industry, indicating a need for the service but may currently have a small user base or draw on a limited dataset. Investing in or combining existing tools could enhance the quality of available tools and improve the accuracy of cost estimates and the associated business cases for early phase projects.

Expert Review

Feedback was received from a diverse group of reviewers with expertise across various sectors of the industry. Commentary ranged from highly positive to more critical, reflecting a broad assessment of the draft report, which covered the entire T&S value chain.

Reviewers provided detailed input, highlighting specific technical issues and omissions. All feedback was documented by the authors and, where within the scope of the study, the concerns were thoroughly addressed prior to submission of the final report.

Some reviewers raised concerns about the perceived lack of hard data in the report, particularly in light of the contractor's prior access to detailed information through work such as the review of T&S costs for the Porthos project commissioned by the Dutch government. However, as the authors clarified, much of that information – as well as similar data from other projects – is proprietary and therefore could not be included. For this study, only publicly available data was used, supplemented by the contractor's expertise and experience in developing cost estimates.

The contractors have proposed several recommendations to support more robust cost analysis in future studies, including steps to enable better access to relevant data.

Overall, feedback on the report has been positive.

Recommendations

It is recommended that a follow-up study, Phase 2, be considered. Phase 2 would aim to collect new data and/or develop new/improved modelling capabilities to address the highest priority areas and data gaps identified in Phase 1, with the merits, scope, feasibility and cost of progressing this follow-on study developed.

Existing estimating tools commonly used in the oil and gas industry – for example, those used for pipeline installation or well costing – offer a solid foundation for calculating capital and operating costs. These tools can be effectively adapted to estimate costs for CO_2 T&S. When applied within a gated development process, these tools have demonstrated their ability to produce reliable estimates. As such, they are well-suited for use in CCS projects. Based on a review of available information and an understanding of the typical project development cycle, the following recommendations have been summarised from the main report. These are intended to help address current gaps in the T&S cost estimating processes used by stakeholders:

- **Standard Project Process and Cost Estimate Guideline**. Cross-sector experience has shown that communicating key project details can be problematic due to variations in definitions and scope across industries for stages such as concept design, front-end engineering design (FEED) and detailed design. Misunderstandings in project cost estimation and accuracy can occur and, ultimately, lead to budgetary issues and cost overruns. With an expected increase in project volume and in government financial contributions, a standardised project development process and guideline on cost estimation and accuracy would benefit all parties and be particularly helpful when comparing competing requests for funding. When governments are considering financial support, understanding the risk of potential cost escalation is crucial. Production of a guide to standardise industry terminology is recommended, including an overview of a gated process, together with details on cost estimation and accuracies.
- **Emitter Base and Utilisation Mapping**. As observed in this study, the utilisation of installed capacity (for both the transport and storage elements) by intermittent users of T&S systems is low because of the nature of their business. Similarly, capacity built for unspecified (but anticipated) users leads to low T&S capacity utilisation early in the project life and can also lead to system underutilisation throughout the whole project life. The effect that underutilisation of capacity has on the cost of storage can be high. While it is accepted that this is a difficult task in a developing sector, it is recommended that it receives significant focus given the potential efficiencies associated with operating a system that is appropriately sized for the emissions.

- **Regional Planning Tool**. In the USA, local and national governments are supporting CCS projects through programmes like the 45Q Tax Credit and, in the UK, via the Cluster Sequencing process, with its two main tracks. These programmes aim to allocate funding efficiently across various projects. In some regions, planning for decarbonisation hubs or single emitter projects is simpler due to the proximity of emissions and storage options. However, in areas with dispersed emitters and multiple storage options, planning is more complex. Ideally, competition would award funding to projects that met government objectives, including cost criteria. However, market complexity and the cost of preparing funding estimates can lead to missed opportunities for cost reduction. Developing tools to systematically pair emitters and storage options would help identify the best projects and aid decision-making for governments and other stakeholders.
- **Shipping Cost Tool**. The report highlights a significant market potential for shipping liquid CO_2 across Asia (including Australia), Europe and North America, noting that lifecycle costs can vary widely. With cost factors generally well understood due to the shipping industry's maturity, stakeholders in CCS projects must consider these when estimating costs. Given the potential scale of liquid CO_2 shipping, it is recommended that a framework for cost estimation is developed to inform early project decisions and build robust business cases.

IEAGHG

CO_2 Transport and Storage Cost Review

Xodus CCS T&S Report

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REVISIONS & APPROVALS

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1 EXECUTIVE SUMMARY

Recent climate commitments and government policies are accelerating carbon capture and storage (CCS) project development worldwide, with an increasing number of projects and regions considering deploying CCS at scale.

The cost of the CCS Transport and Storage (T&S) elements of the CCS value chain has been studied by both public and private sectors for decades; however, the number of constructed and operational projects remains relatively low. Consequently, the understanding of the cost to build and operate these systems is still relatively limited.

The IEAGHG acknowledges the current challenges in estimating the cost of T&S elements of the CCS value chain and has commissioned Xodus Group to investigate this topic in greater detail. The objective of this study is to present the current publicly available cost information, discuss data limitations, and identify areas for improvement to aid stakeholders in understanding the costs involved in the CCS T&S systems at different stages of the project's life cycle. The following sections outline the findings from each task.

It is important to note that the term "cost" is frequently used in literature and industry to denote both the price of a service or equipment and also the associated expenses for transporting and storing CO_2. This dual usage of the term can lead to confusion. Therefore, in this document, we define the following specific terms to facilitate clearer discussion:

- Life of project T&S cost: A general term used to indicate how changes in Capex, Opex or throughput will vary the unit cost of transporting one tonne of CO_2 over the entire life of the system. The cost does not include financing or return allowances, subsidies or revenue risks.

- Tariff: A unit cost that encompasses the Capex, Opex, financing, return for the developer, tax, etc. and considers throughput risk for a given system. The tariff will include allowances for construction and operation risk as well as revenue risks. The tariff represents what a developer would charge an emitter to use a T&S system.

1.1 Task 1 – Establish Classifications

Create design scenarios for CO_2 transport and storage systems, reviewing feasible systems and key variables for large-scale networks.

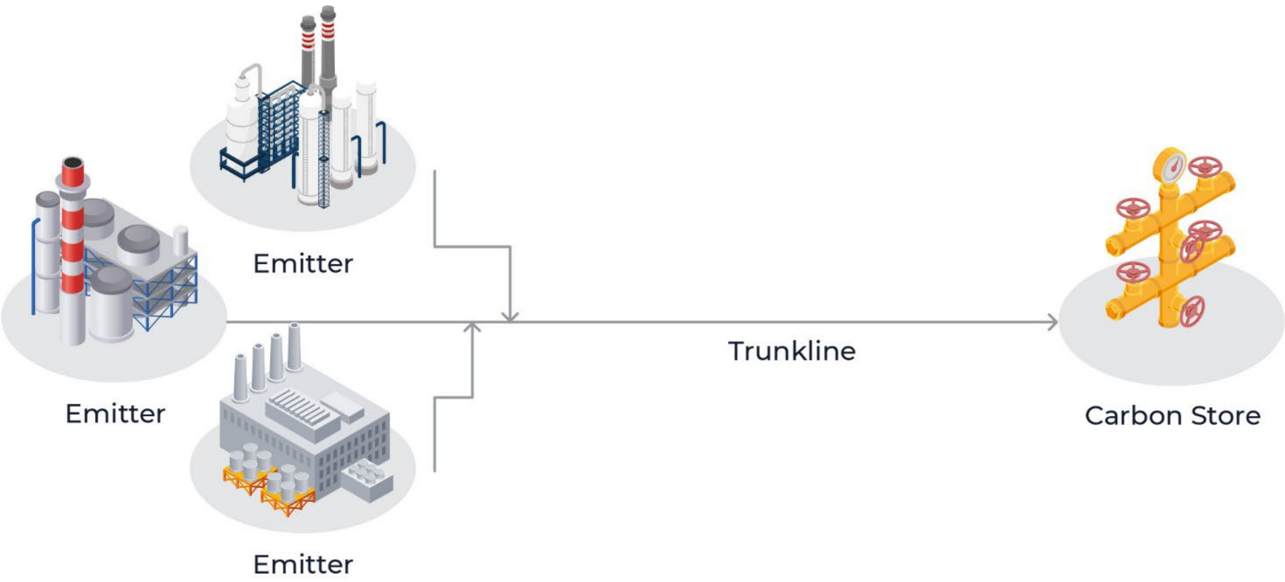

Figure 1.1 - Carbon transport and storage system mapping

A review of the available transport and storage options shows that there has been little movement in technology development in recent years. In general, CO_2 can be transported via pipeline at varying temperatures and pressures or in a tank as a liquid by ship, rail, or road.

There are currently two predominant options for large scale permanent storage of CO_2; storage in depleted hydrocarbon fields or storage in saline aquifers. Other storage options are discussed in literature (including organic shales, unmineable coal seams, and flood basalts), but these are not widely considered to be current options to permanently store CO_2 at a megatonne per year scale.

Transport and storage options for CO_2 systems are limited but they are broadly interchangeable, allowing flexibility in the system design. For example, liquid shipping can pair with any storage option, and saline aquifers can receive CO_2 from any transport method. Multiple transport methods can also be linked together to move CO_2 from emitters to stores. While some pairings have lower Life of Project T&S Costs, storage options are generally agnostic to the selected transport method. Factors such as the distance between the emitter and store location, as well as the geography of the surrounding areas, will significantly influence project design. This, in turn, affects the Life of Project T&S Cost.

1.2 Task 2 – Case Studies

Review public information on CCS network costs in North America, Europe, and Asia/Pacific, describing the type of data available in these regions.

To allow a focus on projects and regions where CCS transport and storage projects are more developed, the publicly available list of projects complied by the Global CCS Institute was screened to highlight those projects that are projected to have a throughput of more than 0.9 million tonnes per year and are stated as being in "advanced development", "construction", or "operation". This screening step aimed to focus on mature and reliable public data sources, particularly information published by government departments or affiliated organizations.

The review confirmed the initial premise of the study scope; that there are limited sources of data available and also found that the information available is region and project specific. For example, North American projects largely consist of onshore storage with pipeline transport, and these would not directly correlate to a large number of the projects proposed in Eastern Asia, which are generally more dependent on CO_2 being transported to storage by ship. The conclusion that construction costs are heavily influenced by project specific factors, such as the type of transport being used, was not unexpected and reflects the experience of the Xodus team when developing CCS project estimates. The review of data has highlighted the following important points:

1. Often, the estimate accuracy and other core assumptions, such as contingency allowances, are not reported publicly.
2. The project archetype and other key factors such as pipeline length, store type and well counts are often difficult to extract from the publications making it difficult to understand how these factors influence the costs reported.
3. It is often unclear if there has been an allowance made for project financing in the costs reported, which can play a key role in driving the cost that emitters would pay. Financing costs can add 20-30% to a Life of Project T&S Cost, creating the tariff that a user of the system would pay.
4. The system utilization profile is rarely stated in detail. It can be difficult to assess if a cost is based on the near-term project usage or its theoretical capacity that may be reached in the future.
5. The cost base is not often stated, and assumptions need to be made based on publication dates which is an issue given the surge in project cost inflation (particularly in Europe) between 2021 and 2024.

Some CCS Projects have reported more detailed cost data than others. HyNet (UK), Porthos and Aramis (Netherlands), Northern Lights (Norway), Quest and Alberta Carbon Trunkline (Canada) show unit costs, either Tariff or Life of project T&S costs ranging from £15/t to over £90/t. The review recognised the costs reported are influenced by factors like archetype, project phase, capacity utilization, and financing. Understanding why the range of costs reported is so large is challenging without detailed supporting information which was often not reported alongside the costs despite extensive investigations on the topic by the project team. The range of costs presented for these mature projects does underline the inherent challenge for stakeholders when attempting to understand realistic and likely out-turn costs for projects currently under development.

Given the relative lack of data available in the public domain, the subsequent tasks of the study aimed to provide valuable insight into the CCS sector using Xodus knowledge and experience in developing cost estimates for CCS T&S projects. The aim of this approach was to highlight the highest impact elements that drive costs in a typical project and discuss how the wider industry can develop frameworks or tools to help support the progression of CCS T&S projects.

1.3 Task 3 - Critique and Discussion

Discuss the findings from the case studies and highlight elements that may lead to under or overestimation of costs

Task 2 identified that publicly reported costs from mature projects fall across a wide range, which is to be expected given the different archetypes, system utilization and allowances included in the costs. This wide range justifies the initial premise of the study and highlights the need for T&S systems to have cost estimates which consider the characteristics of the specific system being discussed.

The following paragraphs highlight factors in a project business case which can significantly alter the life of project transport and storage costs, by altering the capital expenditure, operating expenditure, or throughput of a system. These project specific factors play a key role in the range of costs found in Task 2. Some of the factors listed are obvious, but the effect of other factors is not and are often not highlighted alongside the published data.

1. Location of Emissions and Store - The distance between CO_2 emitters and storage sites significantly impacts transport system construction and operation costs with longer distances requiring more extensive pipelines or liquid transport solutions. Figure 1.2 highlights the locations of emitters, above 50MW thermal output in Europe as an example of the spread of emissions in the region and the potential distances and local geographies that CO_2 gathering networks may need to cover.

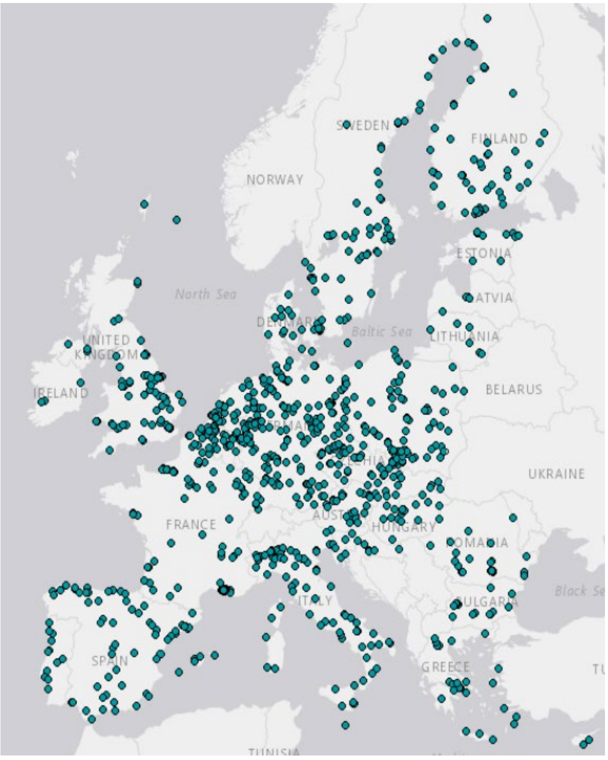

Figure 1.2- Large Combustion Plant, 50MW or greater output, CO_2 Emission Locations in Europe (European Environmental Agency, 2020)

2. Life of T&S Project Costs, Project Life Span and Capacity Utilization - The Capex costs and system capacity of a CCS T&S system are relatively fixed at the outset of the project, with incremental costs for compression, shipping and storage noted in some projects. This upfront investment in infrastructure sets a key element of the life-of-project T&S cost for the entire lifespan of the project. T&S system operational life can span decades and may depend on project capacity (storage) and assumptions on useful life. System utilization can also vary over the life of the project due to external factors such as changes in

government policy or factors within the control of the developer, such as system reliability. These factors have a strong influence on the total volume of CO_2 stored for the initial investment and the ultimate Life of Project T&S Cost but vary from project to project.

3. Early Operations Utilization and Future Pipeline System Expansion – Pipeline transport systems benefit from potential significant economies of scale, where the cost of incremental capacity is considerably lower if specified during the design phase of the project. Deciding whether to install capacity ahead of demand is crucial for most hub projects, as it involves balancing initial capacity investment with future demand projections. To illustrate this issue, Figure 1.3 shows the capacity utilization of a notional 15MTPA Transport and Storage (T&S) hub over the project's lifetime. It assumes that the hub is designed to accommodate regional emissions, but capture capacity is developed over time, influenced by construction activities, local carbon pricing, and the number of emitter projects joining the hub. In this example, the system's lifetime utilization is 74%, meaning an average of 11MTPA is used out of the available 15MTPA throughout the project's life. With capital expenditure fixed, the Life of Project T&S Costs will be calculated based on 11MTPA rather than 15MTPA, resulting in higher costs per tonne stored. Additionally, revenue flows and the time value of money will amplify the impact of lower early-life utilization. This is a particularly challenging issue to address for developers but can have a major impact on the Life of Project T&S costs.

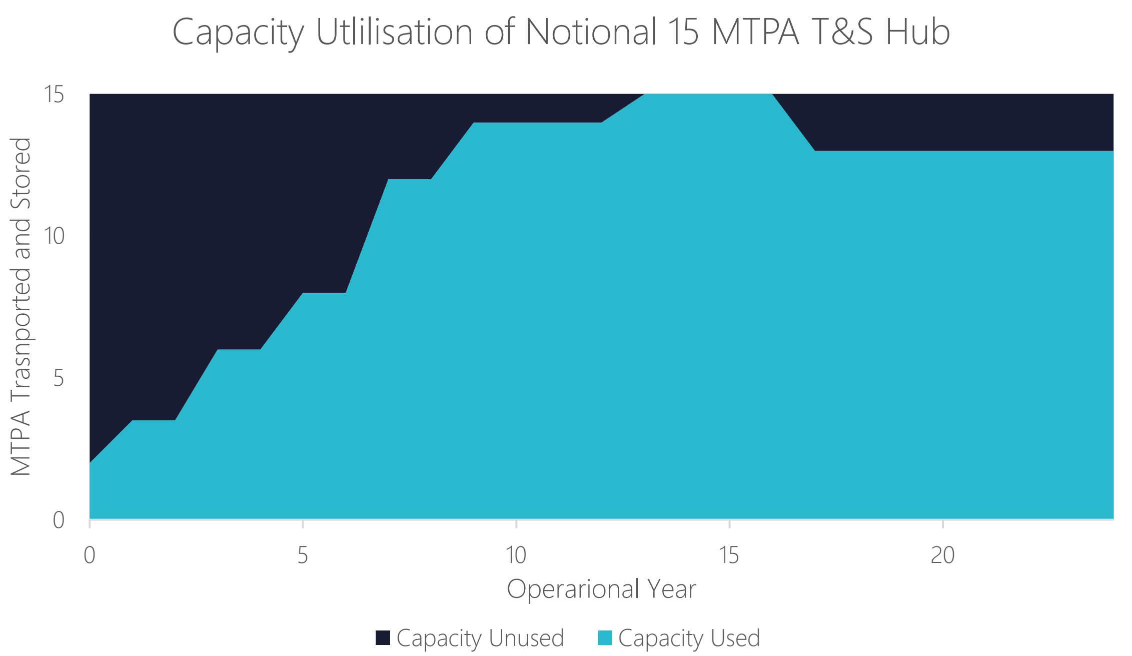

Figure 1.3- Capacity utilization example

4. Types of Emitters and System Utilization - Cluster-type CCS developments connect multiple emitters to a common transport and storage system, with emitters varying in CO_2 flow patterns. Base load emitters, such as manufacturing plants, generally aim to maintain a consistent CO_2 flow to achieve high production rates of their products. In contrast, intermittent emitters, including dispatchable power plants or certain waste-to-energy plants, naturally experience more variable CO_2 flows due to market dynamics. In order to accommodate all emitters, the T&S system is normally designed to manage peak capacity, ensuring emitters can store CO_2 without constraints. However, this flexibility means that actual annual storage volumes are lower than system capacity,

leading to higher overall life cycle cost of T&S due to lower utilization. Therefore, the types of emitters need careful consideration during project design to understand system utilization and its impact on costs.

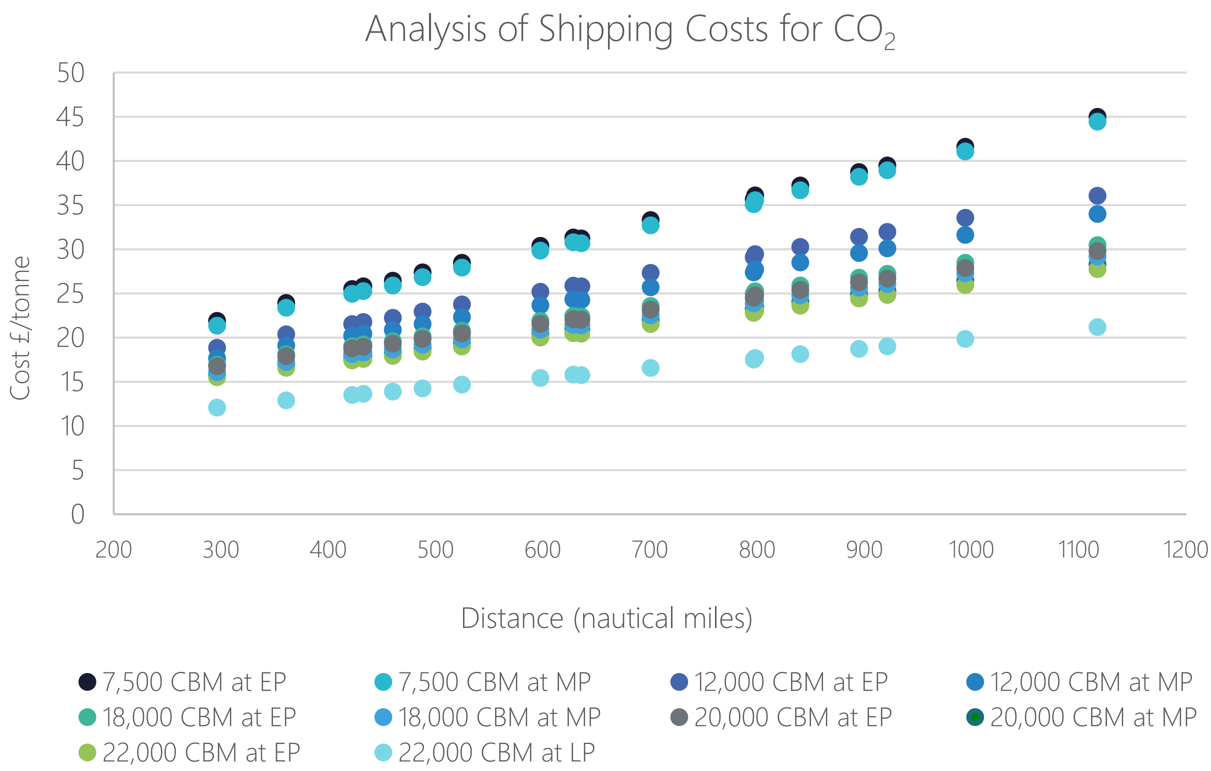

Figure 1.4 - Cost of shipping range for European routes (Clarksons, 2024)

5. Cost of Liquid Transport by Ship - Currently, liquid CO_2 is transported in small volumes and is primarily used in the food industry. A recently published study for the CCSA by Clarksons (Figure 1.4) highlights that shipping costs between emitter and storage locations vary widely based on vessel size, distance, storage pressure and speed. Reported costs from this study range from £12 to £45 per tonne in 2024. While this is a broad range, the variables that influence the out-turn cost are well known and therefore improving the accuracy of the predicted costs is achievable using existing estimating processes.

6. Reservoir Storage Potential and Emitter Volumes - One element of optimising storage costs involves matching the lifetime volume of the store to the expected CO_2 volume from emitters, considering both storage and transport costs. A transport and storage system that requires a number of disparate stores or a larger number of wells to be developed to meet the capacity of the transport system over the project life, will likely require a higher level of Capex. Over the project life, a T&S system that can utilize fewer stores or have a lower well count would have a lower Capex spend and would lead to lower Life of Project T&S Costs.

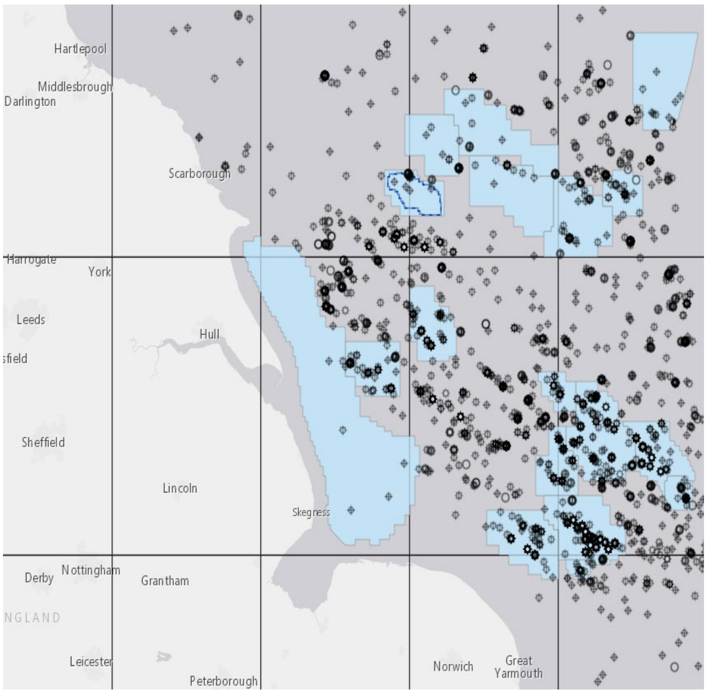

Figure 1.5 - Legacy wells (Black Dots) drilled in UK Southern North Sea Storage Licence (Blue Shaded) Areas (NSTA, 2024)

7. Historical Well Integrity and Implications for the Store - When assessing potential CO_2 storage locations, the integrity of the site is thoroughly reviewed to prevent unplanned CO_2 releases. This assessment process includes evaluating geological release mechanisms and also the impact of existing wells which are themselves a potential leak path from the store. For depleted hydrocarbon reservoirs, exploration, appraisal, and production wells have been drilled into the reservoir and later decommissioned. For saline aquifers in mature hydrocarbon basins, similar wells may have been drilled through the aquifer to reach deeper hydrocarbon reservoirs. Legacy wells in hydrocarbon reservoirs pose a risk to the integrity of CO_2 storage sites, potentially leading to expensive remediation activities. It is important to understand the extent to which the risks associated with legacy wells can increase the costs of CCS projects.

8. CO_2 Specification, Impurities and Store Operation - CO_2 captured from different sources contains various impurities, such as hydrogen from hydrogen production plants and nitrogen oxides from gas power plants. Impurities can impact the design of all parts of the system but are particularly important for the store. These impurities can affect CO_2 storage by:

   - Creating reactions that form solids leading to pore plugging, impacting injectivity and capacity.
   - Changing the physical properties of the CO_2 stream including density and viscosity, which can change the expected injectivity and capacity.
   - Introduce solids that occupy pore space.

   Understanding and managing these impurities during the design phase is crucial, as addressing them after they enter the reservoir is challenging or impossible. Options include reducing impurities before injection or building redundant capacity in the storage system. Both approaches require additional capital and operational expenditure, leading to tension between system users and storage operators. The impact of impurities on the transport and storage (T&S) system is complex and project-specific, affecting costs and tariffs. Proper management by all stakeholders is essential to avoid significant tariff increases or permanent capacity reduction.

9. Store Pressure, Flow Assurance and Operating Expenditure considerations - Pipelines are typically designed to transport CO_2 at high pressure (generally in the range of 100-140barg) to maximise their capacity and minimize installation costs. Injecting this high-pressure fluid into a depleted hydrocarbon field with lower initial pressure can cause well and reservoir integrity issues due to low temperatures from the drop in pressure from the pipeline

to the store. Managing this pressure differential may require additional equipment or complex well design, increasing Capex and Opex costs for the storage part of the system. Understanding these variables and their long-term impacts for specific projects is crucial for efficient system design and cost identification and management.

10. Cost of Store Monitoring and Assurance - Measurement, Monitoring and Verification (MMV) of CO_2 stores is an important part of the regulatory framework for CCS and aims to ensure the store performs as planned and the CO_2 remains permanently stored, preventing environmental and societal impacts. Costs for demonstrating this vary regionally, influenced by global conventions such as the 1996 London Protocol, OSPAR and also local regulations. Regulations are still developing in some areas, with the European directive providing a widely adopted framework that includes baseline assessments, operational monitoring, and post-closure monitoring for around 20 years. Technical approaches and costs to satisfy the regulations will differ and are store and region specific but monitoring costs are known to be significant for all projects. Accordingly, the cost of monitoring the store can be a source of uncertainty in the life of project storage costs, as costs are variable until monitoring plans are set with the applicable regulator.

1.4 Task 4 - Recommendations

Reflecting on the findings from tasks 1 to 3, identify where additional tools, data, or processes would materially improve cost estimating accuracy or improve the transparency of the process for stakeholders. The recommended tools will be considered and developed in a second phase of the project.

Based on the review of the available cost information and insight from the Xodus team, it is clear that there are elements of the typical cost estimating process that can be improved by developing standard tools or processes for the industry. The tools and frameworks proposed for consideration and development by the IEAGHG members in Phase 2 of this study are as follows:

- Standardised Cost Metric Reporting Framework: Produce a standard framework for reporting CO_2 T&S costs, to provide clarity on the basis of published costs. This framework would help stakeholders understand and compare published costs effectively.
- Standardised Cost Database: Develop a database of "core costs" for T&S which could be used to build higher confidence cost estimates for early phase development projects. The database would be populated using data from industry stakeholders to provide confidence in the output of such a tool.
- Standard Project Process and Cost Estimation Guidelines: Develop guidelines to standardize cost estimation and project development stages, helping to reduce misunderstandings, particularly when making comparisons between projects, regions and technologies and improve cost estimate accuracy.
- Emitter Base and Utilization Mapping: Bring a focus on understanding system capacity and utilization to identify potential project efficiencies, provide more accurate utilization estimates and help improve the accuracy of Tariff estimates during the early phases of a project.
- Regional Planning Tools: Create or invest in existing tools to systematically pair emitters and storage options, aiding decision-making for governments and other stakeholders involved in planning at a regional level. This is particularly relevant in regions where Governments are shouldering most of the costs across the entire value chain.

- Shipping Cost Tool: Develop or invest in existing tools to accurately estimate the costs associated with liquid CO_2 shipping, enhancing early project decision-making and improving cost accuracy.

It is noted that bespoke tools are already in place that deliver some of the functionality described above, and regional or national stakeholders may benefit from investing in their further development to improve their capability and accuracy.

1.5 Conclusions

This review confirms the initial premise of the study, that there are limited publicly available sources of recent and useful cost information published. The information that is published shows a wide range which is expected given the various locations and project archetypes in the published data.

An informed user of the published cost information may be able to interpret the data and use it in an appropriate way, at an appropriate time in the project lifecycle to inform decisions being made on projects, policy, or investments. Understanding the technical and commercial aspects of a given project allows the informed user of the data to narrow down the range of costs, albeit from a small data set and reduce the potential for misunderstandings of cost.

However, the published cost information does suffer from a lack of clarity on the underlying assumptions that drive the estimates. This issue is to be expected given the relative complexity of the systems, the confidential nature of some of the important variables, and the general uncertainty of key items such as project lifetime capacity utilization. This issue does significantly increase the risk of inappropriate cost data being used as either a benchmark or to set policy. Even well-informed users of the data may fall foul of this issue because of the complexity of the problem, and it would be unsurprising if mistakes have been made previously where this data has been used.

The issues above can be mitigated by developing a standard reporting framework for costs and by using a standard project process to develop those costs. It is thought that this solution to the problem could be easily implemented in conjunction with stakeholders by combining existing similar processes used extensively in industry and forms one of the key recommendations from our work on the topic. In addition to the standardized reporting metrics and processes, developing a T&S specific cost estimating database for common equipment, in collaboration with developers, could be advantageous. Industry-wide benchmarking databases already exist for oil and gas projects and have been utilized by industry for an extended period. The use of benchmarking databases for Oil and Gas projects suggests that developing a similar resource for CCS projects is both useful and feasible. It is known that developers and existing providers of benchmarking services are already developing CCS specific cost databases and there may be benefits in the IEAGHG members focusing and investing in one of the existing databases for this purpose.

Additional recommendations are provided to help to improve Capex and Opex estimates for individual projects. These tools and frameworks are already in use within industry, indicating a need for the service but may currently have a small user base or draw on a limited dataset. Investing in or combining existing tools could enhance the quality of available tools and improve the accuracy of cost estimates and the associated business cases for early phase projects.

The insight and recommendations from this work are informed by a wide range of data sources, interactions, learning, and insight based on many years of experience in this sector. The recommendations aim to develop new or existing tools to close known knowledge gaps in the industry and, importantly, reduce the risk of published cost information being misinterpreted, leading to poor outcomes.

2 INTRODUCTION & PROJECT SCOPE

Carbon Capture and Storage (CCS) is seen as one of the key technologies to help carbon intensive industries meet challenging global emissions reduction targets. A typical CCS value chain is made up of three key elements:

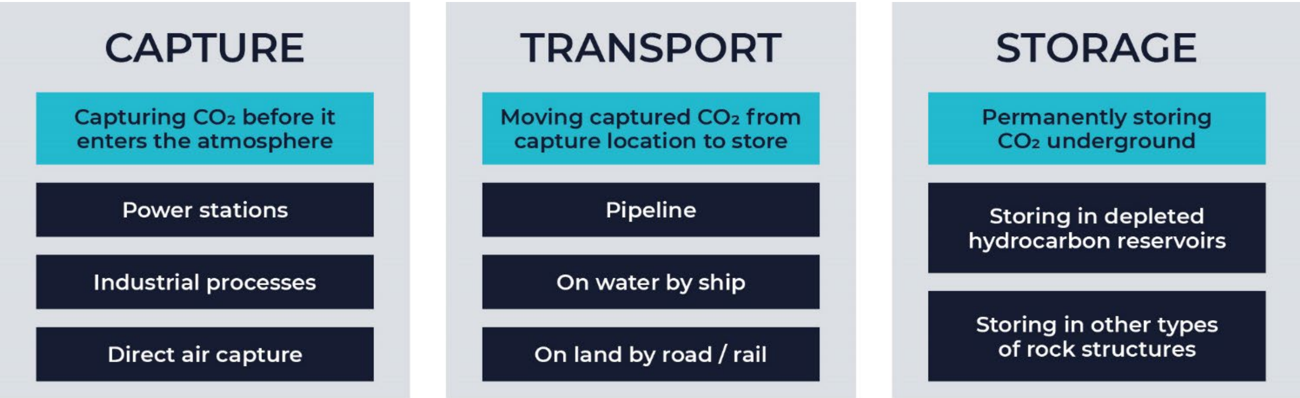

Figure 2.1 - Information on Elements of CCS T&S System

1. Capture
   Removing CO_2 from industrial waste streams before it can be released into the atmosphere. Captured CO_2 is either a by-product of an industrial process (e.g. cement manufacture) or comes from hydrocarbon combustion processes such as power stations, energy from waste plants or other petrochemical type processes. Typical system design sees the capture plant responsible for conditioning CO_2 and providing it at suitable temperatures and pressure for transport and storage.

2. Transport
   Moving the CO_2 from the capture location to the storage location. Two categories are commonly used for transporting CO_2. Firstly, the CO_2 can be moved via pipeline at ambient temperature and a range of pressures. Alternatively, CO_2 can be transported in ships, rail, or road tanks as a liquid under various pressures. Large scale systems can use a combination of these methods to transport CO_2 to the store.

3. Storage
   Storing the CO_2 underground in a range of geological systems, either onshore or offshore. This requires the use of wells, similar in nature to hydrocarbon production wells, to inject CO_2 into subsurface rock strata. The well locations and depths are selected to target subsurface locations that can safely and permanently store the CO_2.

CCS system technology has been the topic of research and investigation for decades, with a small number of systems in operation globally. Recent climate change commitments on carbon emissions and policy decisions made by governments across the world are driving a change in the pace and scale of CCS project development. The number of countries investigating the potential use of CCS is expanding, driving increased scrutiny on the likely costs of large-scale projects.

Given the nascent nature of the industry, the cost of entry, and the link to national emission reduction targets, it is typical for governments to be involved in the provision of funding for CCS projects, via direct or indirect financial support. A significant amount of information currently in the public domain to help inform and support policy and funding decisions for CCS projects is based on academic studies, with relatively little published about the out-turn costs of real-world projects. This is seen as a challenge for all stakeholders in the industry, when attempting to make decisions on the development of new or early phase projects.

This constraint has been recognised by the IEAGHG. To provide further clarity, Xodus have been engaged to review and critique the publicly available information on behalf of the IEAGHG members. The objective of the review is to highlight the information currently available, discuss the limitations of the data and identify areas of improvement, to help stakeholders gain a better understanding of potential costs associated with the Transport and Storage elements of the CCS value chain,

This report presents the findings of the review, alongside recommendations for the development of estimation tools to help improve system construction and operational cost forecasting.

2.1 Project Scope

This study reviews publicly available information that can be used to inform stakeholders in the CCS industry, while considering the applicability and accuracy of the information when used for policy setting or general early phase investment decisions. The scope of work follows an initial request produced by the IEAGHG executive, developed in conjunction with interest from group member nations and organisations. The scope is split into 4 distinct tasks, as detailed in the following paragraphs.

Task 1 – Establish Classifications

Produce a range of design scenarios for differing CO_2 transport and storage systems, based on typical capacity ranges. This task reviews the type of systems that are feasible for a large-scale Transport and Storage (T&S) network at the "building block" level and discusses the key variables for each of the elements of the system.

The primary purpose of the first task is to ensure all the viable system designs are highlighted and considered in the subsequent tasks.

Task 2 – Case Studies

Review all publicly available information on the cost of building and operating large scale CCS networks, to understand the quality of information available to support decision makers in early phases of project development or policy making decisions. The regions of North America, Europe, and Asia/Pacific (including Australia) were included in the scope of review.

The output of this task helps inform discussions around the quality and breadth of information available in the public domain. Case studies have been produced to highlight the types of information publicly available and how applicable and useful the information is for stakeholders in 2025.

Task 3 - Critique and Discussion

Task 3 considers the trends found in publicly available information and considers, using the Xodus knowledge base, what areas may lead to under or overestimation of costs if the publicly available information is used to develop front end business cases.

This task will help to highlight what parts of T&S delivery chain drive capital and operational expenditure (Capex and Opex) and the linkage to tariffs paid during the lifetime of CCUS projects.

Task 4 - Recommendations and Basis for Phase II

Task 4 is a reflection on the critique and discussion from Task 3 areas, where additional tools or data have been identified that would materially improve the current approach to cost estimating and front-end business case development. The recommendations will prioritise elements that have a high impact on levelized cost of abatement and project delivery risk.

Based on our findings and the reflection of our experts, recommendations have been made on how to deliver powerful but achievable estimating tools for the sector.

3 NOTES ON DESCRIPTION OF COSTS

The term "cost" can refer to the capital or operational costs of building and operating a system, as well as the cost of transporting and storing one tonne of CO_2. While there is clearly a strong interaction between the capital and operating costs of a system and the cost of transporting and storing one tonne of CO_2, additional cost drivers including project financing, developer profit, and government support payments also significantly impact the lifecycle cost of storing CO_2. The following sections describe how cost estimates are normally developed and define, for the purposes of this report, terms that are used throughout the report for clarity.

3.1 Typical Project Cost Estimation Process

T&S projects utilise much of the same equipment that is used in the upstream oil and gas sector, with some small but important changes in the specifications of the equipment required for CO_2 service. The companies developing T&S projects tend to be organizations with a strong history in the upstream oil and gas sector due to the expertise and understanding of subsurface reservoirs. They are therefore familiar with the design and construction of the key project elements including pipelines, compressors and wells. Other elements of the CCS transport systems such as cryogenic liquid transport by road, rail or ship may however be less familiar to oil and gas companies in regions where these systems are less common in the hydrocarbon value chain.

A typical upstream oil and gas development investment decision will follow a structured process to evaluate the cost and benefits of a given project, as the business case and design are developed. Gated processes are the project evaluation methodology used in the upstream oil and gas industry, where structured reviews are held at set points in a project life to ensure a project is on track and the probable project outcome is aligned with pre-defined objectives. The gated process helps to control project spend and schedule, allowing project stage progression decisions or the opportunity to stop a project if the expected outcome appears to be offtrack. It is ultimately an uncertainty management process to help decision makers understand the level of uncertainty associated with progressing a project, as the level of spend begins to increase. Table 3.1 sets out the typical steps in a gated process:

TYPICAL PROJECT GATE	APPRAISE	SELECT	DEFINE	EXECUTE
Typical Project Maturity	1 to 15%	10 to 40%	30 to 75%	>65%
Target Cost Estimate Accuracy	Low: -15 to -30% High: +20 to 50%	Low: -15 to -20% High: +10 to +30%	Low: -5 to -15% High: +5 to +20%	Low: -3% to -10% High: +3 to +15%
TYPICAL PROJECT Expenditure	<3%	<5%	10-20%	100%

Table 3.1 - Typical gated project process for CCS developments

A key element of a gated process is to ensure all options have been considered and compared in a fair and consistent manner, before selecting a core project concept. For example, project options could consider the selection of a pipeline gathering network, compared to a liquid shipping network. The "best" option for the project would then be selected, typically by comparing a range of factors that drive the success of the project, such as capital cost, operating cost, environmental impact, time to implement, etc. The gated process will provide review check points to ensure that, as the project design matures, the costs and benefits of the project remain aligned with the original goals. This process enables learnings from failed projects to be incorporated, especially where cost estimates have been shown to be erroneous as the project is constructed, or if the option selected cannot deliver the pre-defined benefits.

Project processes, particularly for large infrastructure projects, are expensive. Early phase engineering i.e. Appraise, Select, Define stages and estimating activities can be expected to represent 5-10% of the final capital expenditure. The costs can be above this range if land is required to be purchased given the cost of land purchase in some regions. The primary benefit of this early phase expenditure, often referred to as "Development Expenditure" (Devex), is to give the developer the confidence to commit the remaining 80-90% of the project Capex and life of project Opex, while providing certainty that the project will deliver on its original goals. The large upfront cost involved in making an investment decision for these projects does present a challenge for new technologies or industries, where future revenue streams remain uncertain.

CCS T&S projects are complicated to deliver and have location specific elements including finding and developing the store that strongly impact the out-turn costs of the system. It is important that the risks and uncertainties associated with a project are well understood when reviewing the potential costs of a project, and that sufficient effort has been undertaken to understand likely out-turn costs. Cost estimates that have been produced without sufficient rigour (across effort and cost), are likely to carry a high risk of failing to deliver expected outcomes or may deliver significant inaccuracies in the estimates.

In T&S projects, the commercial dynamics differ significantly from those in traditional oil and gas ventures. One key distinction is that the developer of the T&S project may not bear the full cost, as public procurement or government subsidies often play a significant role in funding these initiatives. This misalignment can introduce a potential bias, creating an incentive to adjust the cost estimate to influence stakeholder decisions on the project. For example P90 type estimates could be presented, which would provide improved confidence that the project could be delivered for the stated costs, alternatively a P50 cost estimate could be presented to reduce the "headline" investment reported for the project.

Given the importance of the accuracy of project cost estimates and the tendency to draw comparison between cost of projects, the quality of publicly reported cost estimates is important for the sector in the current phase of development.

3.2 Unit Cost Definitions

To simplify the discussion in this report, it has been assumed that the primary variables which drive the cost of transporting and storing one tonne of CO_2 are:

- Capex: The capital cost of constructing, commissioning the T&S system, including all expenditure require to finding and develop the store and transport system including any further expansion or remediation activities required during the life of the project. This Includes allowance for growth and /or risk allowances for the project and the costs to decommission the project at the end of its life.
- Opex: The operating cost of the system during its operational life, including energy and staffing costs.
- CO_2 transported and stored: The amount of CO_2 stored, which can be affected by the size of stores available, the reliability of emitters, the T&S system reliability, or the general availability of CO_2.
- Financing costs: The cost to the developer of raising the capital required to build the project.
- Expected return: The return on investment that developers expect for a given project.

Increasing or decreasing any of these variables will ultimately change the cost of storing one tonne of CO_2, when considered over the full project lifecycle. It is accepted that projects business cases are complex and have a large number of direct and indirect factors which influence the outcome. For the purposes of this report, a focus has been placed on the variables listed above as this allows open discussion regarding factors within the control of the project team and removes the influence of direct government incentives or interventions.

For clarity, the following terms are used in this document:

- Life of project T&S cost - A general term used to indicate how changes in Capex, Opex or throughput will vary the unit cost of transporting one tonne of CO_2 over the entire life of the system. The cost does not include financing or return allowances.

- Tariff: - A unit cost that encompasses the Capex, Opex, financing, profit, tax, etc. and considers throughput risk for a given system. The tariff value will include allowances for construction and operation risk as well as revenue risks.

It is important to note the cost of financing for these major projects is significant given the scale of the Capex involved and the relatively nascent nature of the industry. The financing element of a tariff value can represent circa 20-30% of the total Tariff. It is important to recognise and identify when financing costs are included in the unit costs reported, because of the scale of impact they have.

it is necessary to make this distinction between reported costs, given the range of data found during the review. Where possible, the type of cost being reported is defined in this report. If it is not clear how the cost has been generated, then this has been stated.

4 TASK 1 - TRANSPORT SYSTEM ARCHETYPES

Carbon emissions and storage sites are often not co-located, which creates a requirement to transport CO_2 from the source to the storage location. The physical properties of CO_2 enable multiple transportation methods, similar to those used for oil and gas, such as pipelines and shipping. Like traditional oil and gas transport systems, several factors influence the choice of CO_2 transport for each CCS project.

The factors that influence transport methods are:

- Geographical location of emitters and storage sites: the distance and the type of terrain between the source of CO_2 and the storage site.
- Quantity of CO_2 to be transported: the amount of CO_2 that needs to be transported.
- Country specific regulations: regulations regarding the transportation and storage of CO_2 vary across countries
- Country specific infrastructure: countries may have existing transport and pipeline infrastructure that may influence decisions. Existing port, road, and rail infrastructure will also influence the viability of transportation methods.
- CO_2 specification: the properties of CO_2 being transported, including pressure, temperature as well as impurities.

The cost of constructing and operating the equipment for the transport element of a CCS system makes up a sizeable proportion of the full life of project storage costs. Like most infrastructure investments, there are trade-offs between Capex and Opex costs when considering the options available.

The following sections discuss the options available for the transport element of the system.

4.1 Scale of Emitter Projects and CO_2 Physical Properties

The objective of a transport system is to efficiently move CO_2 from the emission site to the storage site at scale. However, the capacity of such a system will vary depending on the number and type of emitters connected to it. Table 4.1 offers approximate CO_2 emissions for some typical T&S system users to provide context for the capacities discussed in this report.

	CEMENT PLANT	COMBINED CYCLE GAS POWER PLANT	ENERGY FROM WASTE PLANT
Plant Capacity	817 kTPA Klinker (Castle Cement Limited, 2024)	750MW Electrical Output Dispatchable	750 kTPA waste (Pennon Group, 2010)
Emissions	0.8 MTPA	2 MTPA (Department for Business, Energy & Industrial Strategy, 2021)	0.9MTPA

Table 4.1 – Approximate mass of CO_2 produced by a selection of CCS emitters.

CO_2 is a low-density gas at ambient conditions, around 2 kg/m^3, requiring impractically large equipment to transport any significant mass of CO_2. However, by changing the pressure and temperature, the phase of the CO_2 stream can be altered from a gas to a liquid and vice versa with corresponding changes in density, making it much more practical to transport in tanks or by pipeline.

The following table provides the density values for a pure CO_2 stream at varying pressure temperatures and phases to illustrate how the density of CO_2 varies with changes in phase, pressure, and temperature.

PHASE	GAS	GAS	LIQUID	LIQUID
Temperature (ºC)	6	6	6	-55
Pressure (barg)	0	30	100	5
Density (kg/m^3)	2	78	944	1167

Table 4.2 - Density of pure CO_2 at select pressures and temperatures.

It can be seen that there are significant differences in density between phases which will have a significant impact on the design and operation of a CO_2 transport system. It should also be noted that the introduction of impurities to a CO_2 rich stream can impact the pressure and temperature phase boundaries, something that is considered during the design process.

4.2 Pipeline Transport

Transporting CO_2 through pipelines is currently the most common method with a relatively mature market in the USA and Canada, where CO_2 is used for Enhanced Oil Recovery (EOR). Europe and the Asia Pacific also have extensive experience in transporting natural gas, crude oil, and chemicals through pipelines. The benefits of pipeline transport are:

- Cost Efficiency: Large volumes can be transported to the required location and provide a constant supply without the logistical delays often experienced with non-pipeline transport solutions, minimising delay costs.
- Supply Chain: The supply chain to manufacture and install CCS pipelines is almost identical to that used for high pressure natural gas pipelines. The pipelines are typically made from Carbon Steel and the process for installing pipelines onshore or offshore is well understood.
- Operations: Pipeline operations will be similar to oil and gas transport. The operational framework for a pipeline is very similar to operating a hydrocarbon pipeline, although there are some important differences.

Pipelines can be designed to transport CO_2 as a gas, liquid, or a combination of both. However, a number of projects in development are based upon transporting CO_2 at ambient temperature and a high enough pressure that the physical properties of the CO_2 are equivalent to a liquid in terms of density and a gas in terms of viscosity (often referred to as dense phase gas). Transporting CO_2 under these conditions maximises pipeline capacity and optimises project Capex by balancing pipeline diameter costs with the complexity and expense of compression systems needed to achieve the required pressure for dense phase gas.

The reuse of existing pipeline infrastructure to reduce project costs is being considered by a number of projects in development as well as new build pipelines. Reuse of pipelines is not a straightforward activity, often bringing technical and operational challenges that need to be addressed. Material compatibility, historical pipeline integrity issues and challenges with the operational history of the pipeline, are key influences on the cost of repurposing pipelines for CO_2 service. Reusing pipeline infrastructure does however bring the benefit of using existing routings, deferring decommissioning costs and providing potential Capex savings through reuse of the pipeline itself.

The following paragraphs highlight how the use of pipelines in a system can drive changes in the life of project storage costs.

T&S Downward Cost Pressures for Pipeline Transport

- The incremental Capex of increasing the capacity of a pipeline system at the design stage is relatively low, which can help drive down costs for groups of emitters attached to a common pipeline.
- The supply chain to manufacture and install suitable pipelines for a CCS system already exists, allowing the competitive, mature market to help push down construction costs.
- The operating costs of pipelines are relatively low compared to other transport methods, with compression maintenance, inspection and energy costs dominating.
- Pipeline systems are known to be highly reliable and are normally unaffected by logistical issues or weather. The high reliability of such systems helps to push down the costs of transporting CO_2 on a per unit basis.

T&S Upward Cost Pressures for Pipeline Transport

- The distance between the emitter and the store drives the cost of the transport infrastructure. The relationship between the distance and volume that the CO_2 is transported is region specific but will drive the decision to use a pipeline or other mode to transport the CO_2.
- Some projects require dedicated compression for the transport system alone, dependent upon the length of the pipeline and the pressure of the store.
- The cost of installing pipelines onshore is known to vary from region to region, linked to the geography and regulatory frameworks in place. More populated regions or areas with challenging geography such as large elevation changes, can push up pipeline installation costs.
- Pipeline installation costs are linked to the market for installation contractors both on and offshore. During times of high activity, the cost of pipeline installation rises, reflecting normal market tensions.

4.2.1 Requirement for Compressors or Pumps

As previously discussed, it is necessary to increase the pressure of CO_2 to allow any meaningful volume to be transported by pipeline. Compressors or pumps are used for this purpose, depending on the phase of the fluid being transported. Increasing the pressure of the CO_2 does however require significant quantities of energy and the provision of compression equipment incurring Capex and Opex costs. As a result, the pressure at which CO_2 is transported through a pipeline system is a key design consideration for the system developer and decisions are made on this parameter considering the associated costs and benefits.

There are several variables that will influence the selection of the operating system pressure such as the length of the pipeline; the initial pressure of the store, the pipeline diameter, pipeline maximum allowable pressure, the use of booster compressors/pumps and the stability of the flow through the system. Ultimately the system pressure must be sufficient to allow the CO_2 to flow through the pipeline infrastructure, wells and into the reservoir at the desired flowrate. The reservoir pressure will often increase over time as more CO_2 is stored, adding an additional factor to consider when selecting a system operating pressure.

The source of the CO_2, the capture plant, must consider similar variables when transporting CO_2 at varying pressures within the capture systems and ultimately to the T&S system. For several capture plant technologies, compression is employed to dry the CO_2 from the capture process, which is a critical processing step.

The necessity for the emitter plant to compress the CO_2 presents an opportunity to streamline the amount of compression equipment required for operating the T&S system. For instance, if the emitter's capture and treatment plant can deliver CO_2 at a pressure sufficient to flow through to the store, additional compression equipment may not be necessary. Conversely, if a lower pressure is specified due to other considerations, such as the rating of a repurposed pipeline, it would necessitate the construction and operation of compressors elsewhere in the network to facilitate injection at the storage site.

The requirement and placement of compressors or pumps within a T&S system typically involve a trade-off among several factors, many of which are location and project specific.

4.3 Liquid Transport in Tanks

Transporting CO_2 via tanks (ships, barges, road, or rail) is currently used for small-scale food grade CO_2 transport. The development of ships to transport CO_2 over long distances at relatively large volumes is an evolving market and is expected to play a major role in the early phases of CCS operation in Europe, due to population density and general geography of the region, and also in the Asia-Pacific region due to large distances between many emitters and available stores. For regions where the transport of liquified gasses by rail is more common, for example landlocked countries or areas with limited transport routes by river, CO_2 transport by rail may also be a viable option.

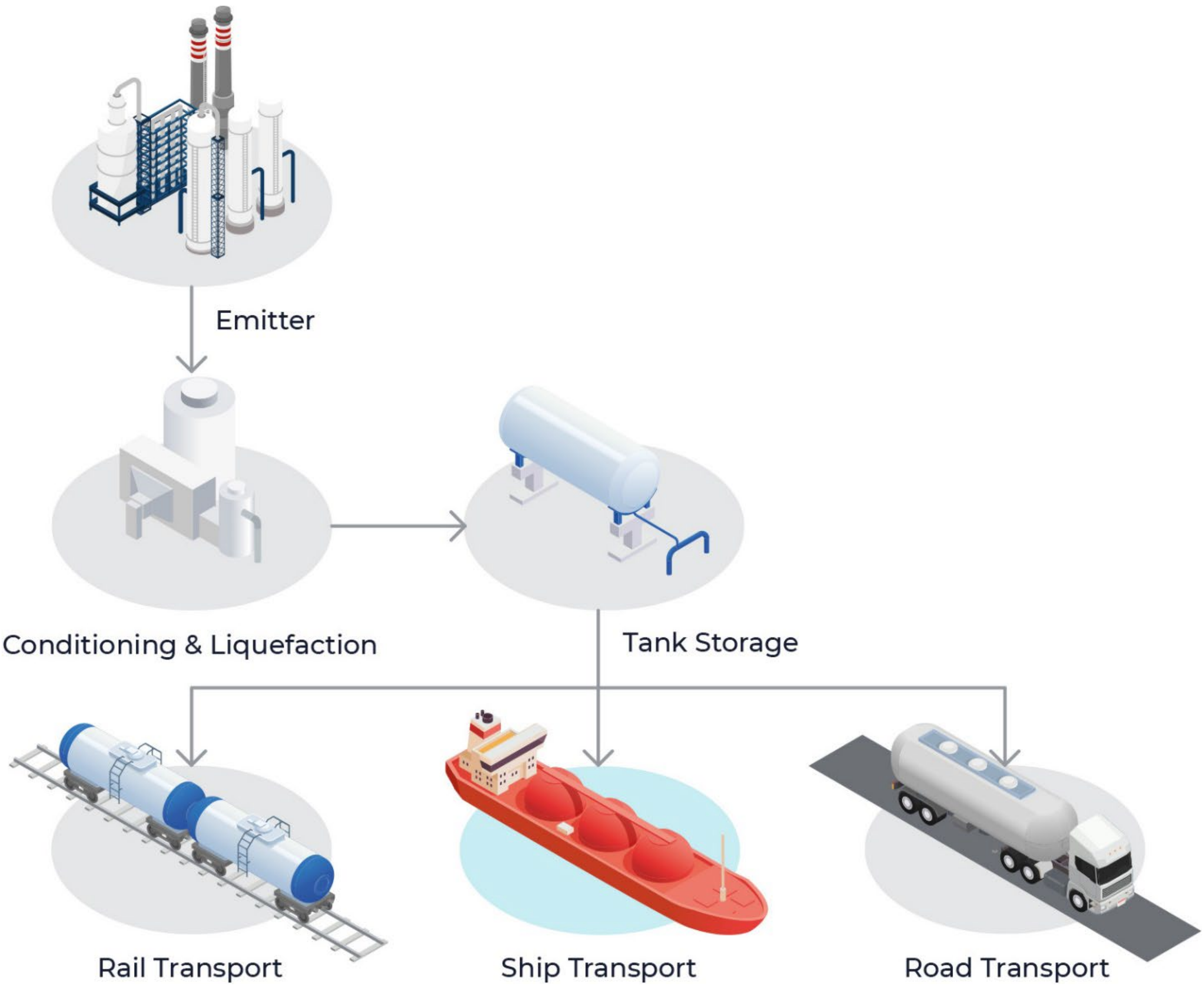

Figure 4.1 - Liquid transport by tank options

To allow CO_2 to be transported via tanks, it must first be conditioned, liquified and then stored at the emitter site, in preparation for onwards transport. At the storage site, a typical system design would include intermediate storage tanks to allow the liquid to be offloaded quickly (in a period of hours). The liquid is then pumped into the store at high pressure via the T&S system pipelines and wells over a period of days/weeks. This design philosophy is typical for products transported by tank in a competitive market, such as liquefied petroleum gas (LPG) and looks to maximise the amount of product moved while minimising the volume of tanks required onshore. Differences in fluid properties between CO_2 and LPGs does however drive changes in design of the tanks and associated systems.

4.3.1 Transport by Ship or Barge

The transport of CO_2 via ship or barge enables stranded emitters that are not located near pipeline infrastructure or who are geographically remote from storage sites, to transfer CO_2 from the emitter location to either a CO_2 collection hub for onwards distribution or directly to a store.

The development of CO_2 ship carriers has been established for over 25 years, albeit at smaller sizes transporting high purity or "food grade" CO_2 on cryogenic liquid carriers. The technology of CO_2 ship carriers is broadly analogous to LPG carriers, where CO_2 is typically stored at temperatures below ambient to optimise the design pressure of the product storage tanks. LPG carrier technology has been in service since the 1950s.

CO_2 when compared to LPG does however have different considerations for liquefaction and thermal management. The CCSA and Zero Energy Platform (ZEP) considered the following conditions in their recent publication for transporting CO_2 by ship (CCSA & ZEP, 2024):

VARIABLE	LOW PRESSURE (LP)	MEDIUM PRESSURE (MP)	HIGH PRESSURE (HP)
Temperature (°C)	-55 to -40	-30 to -20	0 to 15
Pressure (barg)	5-10	15-20	35-50
Density (kg/m³)	1170-1120	1080-1030	930-820

Table 4.3 - Liquid CO_2 conditions, (CCSA & ZEP, 2024)

It is worth noting that the conditions in Table 4.3 will vary with addition or removal of impurities from the CO_2.

Transporting CO_2 by ship at a low pressure is currently considered to be the optimal approach for larger transport volumes. Due to the lower temperature and pressure conditions of an LP type carrier, the wall thickness of the tanks is lower than that of MP and HP for the same diameter tank. However, due to the very low temperatures, a higher grade of material is required for construction and trade-offs need to be made when considering the design of the ship. Careful management of the transport temperature either by actively cooling the tanks or minimising heat ingress is also important for all pressure ranges to minimise CO_2 lost from tanks due to boil off. The capacity, pressure regime and operation of CO_2 carriers is an active area of development for the industry, and it should be noted that the capacity range for each pressure regime is evolving.

The addition of liquefaction facilities, intermediate storage tanks, jetty infrastructure, and shipping freight rate, adds both Capex and Opex for a T&S system. These costs must be considered when comparing transportation by ship with pipeline transportation. The ability to store cryogenic CO_2 in tanks for injection at a later time can assist in smoothing out flow variations from other emitters in the system. However, this operational flexibility will come with additional Capex and Opex.

Compared to pipeline transport, which has several large-scale CO_2 transport networks present in North America, shipped CO_2 solutions for larger emitters is relatively unproven. The small number of built and operating infrastructure for shipped solutions creates uncertainties in estimating the cost of both onshore and ship elements due to a lack of comparative costs.

T&S Downward Cost Pressures for Transport by Ship or Barge

- Large variations in T&S pipeline flow rates, which can be caused by intermittent pipeline-connected emitters or the batchwise nature of shipped CO_2, can be minimized by utilizing CO_2 stored in tanks as a "buffer." By reducing these variations in flow, developers can optimize pipeline design and maximize utilization. This approach may lead to smaller diameter pipelines and lower Capex costs.

- Ships can potentially serve more than one emitter or storage site, offering a degree of redundancy and flexibility between storage sites and emitters.

T&S Upward Cost Pressures for Transport by Ship or Barge

- Infrastructure needs to be built at both the emitter location and store. Additionally, there is the requirement to operate the ships to move the CO_2 over the lifetime of the project. The combined Capex and Opex costs of these elements is known to be significant in the life cycle cost of a T&S system.

- Energy costs to cool and then reheat shipped CO_2 are known to be significant for this transport measure.

- Until sufficient volumes of CO_2 are regularly being transported by ship, the normal efficiencies associated with a fluid shipping market do not exist. Due to the lack of scale of the shipping market and the need to provide a level of redundancy to initial emitter projects, underutilization of the ships could be expected during the earlier years of the market.

4.3.2 Transport by Rail

Rail transport is another means of transporting liquid CO_2 by tank. This option would be favourable in countries that have existing rail infrastructure in place and it can be demonstrated that rail transport is lower cost than pipeline or ship transport methods. Transport by rail is similar to ship transport, where the CO_2 is liquefied close to the emitter, stored in intermediate storage tanks as a liquid and later offloaded to tanks near to the store where it is injected.

The bulk transport of goods by rail varies from region to region, with vast quantities of commodities moved in the mining and extraction industries by rail in some regions. However, generally the transport of liquified gases by rail at similar scale is less common.

Broadly, the same upward and downward pressures noted in the shipping section above, apply to rail transport.

4.3.3 Transport by Road

Road transportation will face similar challenges and provide similar benefits to ship and rail transport but on a smaller scale. The size of road tankers will be dependent on in-country regulations and CO_2 would likely be transported at MP conditions.

This option can become costly for projects that capture CO_2 at a significant rate, due to the relatively small mass of CO_2 that can be transported in each road tank, leading to a high number of road tankers and daily movements being required. Similar to shipping and rail transport, road transport will require intermediate storage.

Broadly, the same upward and downward pressures noted in the shipping section above, apply to rail transport.

4.4 Summary of Transport Options and Capacity Discussion

Pipelines

Using pipelines for CO_2 transport is one of the most common methods considered due to the maturity of the technology and cost effectiveness over shorter distances and large volumes.

Estimating nominal pipeline capacities is complex due to specific design requirements to connect emitters to a store. As previously stated, it is far more efficient to transport CO_2 as a high-density fluid (dense phase gas) although pipelines can be used for lower density gaseous phase transport. The table below provides high-level estimates on how pipeline diameters vary with capacity and distance. The estimates are generated for dense phase CO_2 flow and assumes an inlet pressure of 120 barg and an outlet of 85 barg operating at 6°C with no elevation changes or intermediate compression. Intermediate compression or pumping stations can be utilized to change the capacity of a pipeline system but can add significant Capex and Opex costs depending on the location of the station.

CO_2 FLOWRATE	PIPELINE DISTANCE				
	50km	100km	150km	200km	250km
5 MTPA	16"	18"	20"	20"	22"
10 MTPA	22"	22"	24"	26"	26"
15 MTPA	24"	26"	28"	30"	30"
20 MTPA	26"	30"	32"	32"	34"
25 MTPA	28″	32″	34″	34″	36″
30 MTPA	30″	34″	36″	36″	38″

Table 4.4 - Estimate of required pipeline diameter for high density fluid CO_2 system for a range of capacities and distances.

A pipeline project will incur a proportion of base costs independent of the overall capacity, such as land purchases, installation costs, engineering, and project management. This effectively means that larger pipelines will have a lower cost per unit of capacity than smaller pipelines, but this does vary within a range and economies of scale begin to diminish as capacities increase.

An understanding of the project and its local region is required to develop pipeline costs. Onshore pipelines require an understanding of the geography, access routes and local populations, to ensure the pipeline can be built safely. Offshore pipelines come with a separate set of challenges including water depth and the requirement to use specific vessels to install the infrastructure. A range of factors can impact the cost of pipelines, with costs varying between onshore and offshore, and between regions.

Shipping

Shipping of CO_2 is developing quickly and serves as a crucial solution for emitters without access to pipeline transport infrastructure or in regions where the transport distance mean that pipelines are not economical to install. Shipping capacities will vary depending on temperature and pressure of the transported CO_2, with ships designed for high pressure (HP), medium pressure (MP) or low pressure (LP). The chosen conditions will depend on both technical criteria and economic considerations. In March 2022, CCSA and ZEP published a paper (CCSA & ZEP, 2022), detailing typical pressures, temperatures, and capacities, with information taken from The Northern Lights project, a market review and industry knowledge. It is known that ship design is evolving quickly with new designs being progressed with pressure/capacities envelopes that extend beyond those noted in the 2022 CCSA and ZEP study shown in the table below, particularly the transition from MP to LP.

CONDITION	PRESSURE	TEMPERATURE	CAPACITY
HP	40-50barg	Ambient	<10,000m^3
MP	15barg	Semi-refrigerated (-30ºC)	<15,000m^3
LP	7barg	Semi-refrigerated (-50ºC)	>20,000m^3

Table 4.5 - Shipping conditions for CO_2 (CCSA & ZEP, 2022)

Publicly available data on rail and road transport is limited. The UK HyNet Project published a CO_2 Road and Rail Transport Study Report (HyNet, 2019) as part of their pre-FEED, stating that a cryogenic ISO tank is capable of holding approximately 19.6 tonnes of CO_2 at 20barg and -20 ºC, which is broadly aligned with the MP conditions noted above for ship transport.

The mass of CO_2 that can be transported in a single road or rail tank will however vary by region with local infrastructure and regulations influencing this value. For example, in the United States the estimated capacity for a rail tanker is ~82 tCO_2 or 83m^3 and for an intermodal truck is ~19 tCO_2 or 23m^3 at the transport conditions (Corey Myers, 2024). Regardless of the weight of CO_2 permitted for transport by road or rail in a given region, there is a significant difference in the economies of scale between moving CO_2 by road or rail compared to larger capacity shipping solutions.

5 TASK 1 - GEOLOGICAL STORAGE OPTIONS

Subsurface geological formations have long been proposed as a method for permanently storing CO_2. Subsurface CO_2 accumulations occur naturally within geological systems and can be viewed as a natural analogue for industrial storage of CO_2 using CCS techniques. It is known that a range of reservoir and rock types can be used to store CO_2 with potential storage sites characterised by the following criteria:

- Storage scale: The site must be located in an area that can offer large-scale economically viable storage.
- Depth: A storage depth of 800 meters to 1500 metres is preferential to ensure the pressure of the store is enough to ensure that the CO_2 is ultimately stored as a high density fluid which maximises store capacity. CO_2 must be stored below freshwater aquifers, which are used in industry, agriculture or as a source of drinking water to avoid contamination. At depths greater than 800 metres, aquifers commonly contain saline water rather than fresh water. The deeper the reservoir, the higher the pressure, which can limit the rate at which CO_2 can be injected, as well as the operation of the whole system.
- Stratigraphic setting: The site requires a geological barrier (cap rock/sealing unit) that will maintain its structural integrity, including any existing wells in the structure, over a prolonged period. The reservoir also needs to be capable of storing economical volumes of CO_2.
- Seismic setting: Where possible, storage sites should be located within areas where the tectonic risk is understood. Faulting can normally be expected to be present, so it is critical the failure envelope is known and not exceeded to avoid potential leakage of CO_2 resulting from fault reactivation.
- Injectivity: The rate at which CO_2 can be injected into a formation, is directly related to the formation permeability and pressure.
- Predictability: Interactions between the storage unit and injected CO_2 must be sufficiently understood to ensure that the storage process is not hindered or compromised.

Ultimately these factors need to be considered collectively to understand if a store can be developed and present an economic business case. The following sections of the report list the types of formations that can be used to store CO_2 in a typical CCS T&S system.

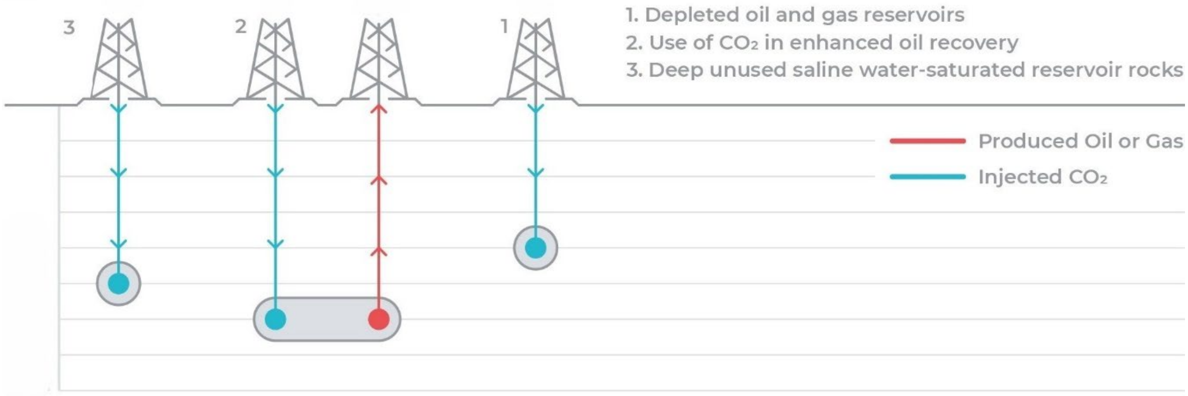

Figure 5.1 - Overview of depleted oil and gas reservoirs, CO_2 enhanced oil recovery and saline aquifers as options for geological storage of CO_2.

5.1 Saline aquifer

Saline aquifers are geological formations comprised of porous and permeable rock that are saturated with saline water. Saline aquifers are known to occur globally, both onshore and offshore, being found on every continent and within most countries. As such, it is commonly agreed that saline aquifers offer the largest capacity for carbon capture and storage (Hughes, 2009). Unless the aquifers in question have previously been targeted during resource exploration, it is unlikely that much of the data required for successful CCS appraisal exists, resulting in a substantial amount of work and cost being required to characterise and evaluate these sites.

Captured CO_2 is compressed to a high density fluid and injected into the saline aquifer at depths greater than 800m (where CO_2 typically exists in as a high density fluid in an aquifer). With increased injection volumes (Ringrose, Greenberg, Whittaker, Nazarian, & Oye, 2017; Worden, 2024), the fluid pressure of the aquifer will increase as a function of:

- The rate and duration of injection
- Reservoir permeability
- CO_2 viscosity
- The ratio of the injection well radius and reservoir compartment (size of the reservoir)
- The differential pressure between bottom hole conditions and the reservoir.

The injection of CO_2 displaces the in-place formation brines, and the injected CO_2 is of lower density than the saline water in the aquifer. As a result, the CO_2 will migrate upwards towards a preidentified structural trap (Figure 5.2).

The majority of the initial CO_2 stored in an aquifer displaces formation brines and the CO_2 injection process can lead to the pressure in the store rising over time. Managing the pressure in the store is critical to prevent formation damage and it can be necessary to drill wells which remove brine and lower the store pressure as CO_2 injection proceeds. The drilling of additional wells and associated treatment systems for the brine would lead to increased Capex and Opex for some storage sites.

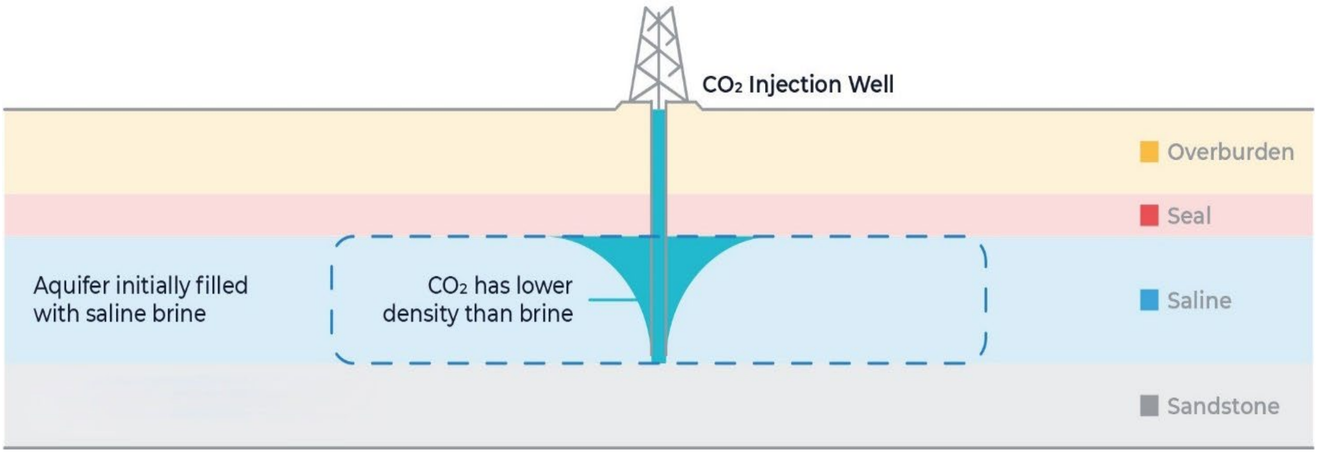

Figure 5.2 - A schematic representation of upward CO_2 plume migration within a saline aquifer, due to the lower density CO_2 versus reservoir brines

The CO_2 is then kept in place by a series of mechanisms (Figure 5.3):

1. Structural/stratigraphic trapping: CO_2 is trapped by an impermeable cap rock (ideally unfaulted to reduce the risk of leakage/fault reactivation) preventing further vertical migration, pooling the CO_2 into a plume laterally at the top of the aquifer.
2. Residual trapping: As the injected CO_2 migrates through the formation, a percentage will become trapped within 'free' pore space due to capillary pressure. Displaced saline formation water and/or injected water migrates back into the pore space as the CO_2 plume migrates towards the seal/trap. The water wets the grains in saline aquifers, so water will flow through the wetting layers, leaving CO_2 (non-wetting phase) trapped in isolated masses (Bruant, Celia, Guswa, & Peters, 2002; Andrew, Bijeljic, & Blunt, 2013).
3. Solubility trapping: The dissolution of CO_2 within saline water over time. The density of saline water increases with CO_2 dissolution and sinks in the aquifer becoming sequestrated.
4. Mineralogical trapping: Injected CO_2 reacts with the saline water, forming carbonic acid. Geochemical reactions between the carbonic acid and the minerals in the aquifer formation result in the precipitation of carbonates (e.g. calcite), providing stable long-term storage.

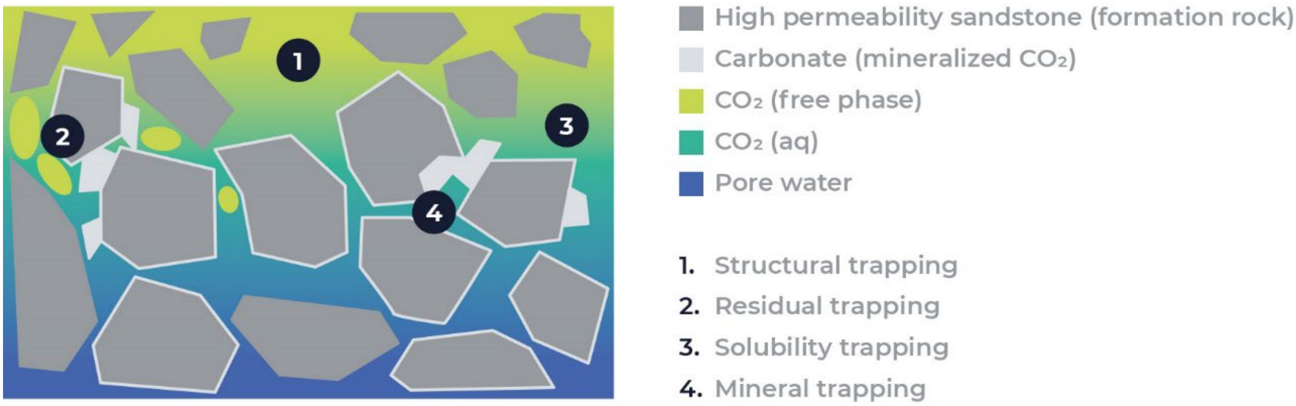

Figure 5.3 - Schematic illumination showing geological trapping mechanisms for sequestering CO_2.

The Sleipner project is an example of a saline aquifer store that is currently being operated in the Norwegian sector of the North Sea. The Aquistore demonstration project in Canada has also been storing CO_2 in a saline aquifer formation. Other similar projects are currently at different stages of planning, including the Northern Endurance project in the UK and Norway's Northern Lights development.

The abundance of the locations where saline aquifers occur and the large size of their structures, make them an attractive storage option globally and are therefore the subject of investigation in all regions investigated by this study.

T&S Downward Cost Pressures for Saline Aquifers

- The abundance of potential saline aquifer stores and their availability away from hydrocarbon producing basins. The abundance of locations provides the potential to reduce transport distances from emitters to more local stores, disparate from hydrocarbon basins, has the potential to significantly reduce T&S costs in some locations.

- Typical saline aquifer "virgin" pressure conditions i.e. stores deeper than 800m are suited to dense phase gas CO_2 injection, simplifying the infrastructure required for injection.

- Unlike depleted hydrocarbon stores, saline aquifers do not need to be located in hydrocarbon basins and the problems associated with legacy wells can be less prevalent as a result.

- Saline aquifers can offer greater storage potential than other options, leading to cost-saving opportunities related to well Capex.

T&S Upward Cost Pressures for Saline Aquifers

- There is usually limited subsurface (seismic and/or wells) data available when compared to hydrocarbon fields. Therefore, there is the potential for increased development costs and schedule to demonstrate the adequacy of the store to regulators.

- Elevated well and formation damage risk from Halite (salt) precipitation near the well bore compared to depleted gas reservoirs, driving potential higher Opex through the field's life to resolve the salt precipitation issues. Wells that are subject to large variations in flow can also be at a heightened risk of Halite fouling complicating the operation of the system.

- Potential requirement for saline water production wells and treatment systems to manage the reservoir pressure and realise the full capacity of the store, adding significant Capex and Opex costs to a saline aquifer development.

- Saline aquifers have relatively low storage density (i.e. amount of CO_2 stored in tonnes per unit volume of store) when compared to depleted hydrocarbon fields, which leads to them generally requiring a larger geographic area to store a given amount of CO_2 than a depleted hydrocarbon field. The cost of the infrastructure and seismic needed for the large area can in turn increase storage costs.

5.2 Depleted Oil Field

Depleted oil fields are fields which previously produced oil, and are typically composed of porous and permeable sandstones, limestones, or dolomites. They have generally been exploited to a degree where further oil production is deemed uneconomical or not technically feasible. Water injection and/or Enhanced Oil Recovery (EOR) may also have been utilized to assist and increase hydrocarbon production of fields nearing end of life.

Depleted oil fields are geographically more restricted when compared to those of saline aquifers, due to the specific geological requirements from source to sink allowing for the maturation, migration, and storage of hydrocarbons (Tissot & Welte, 1984). They do however similarly occur both onshore and offshore, predominately in sandstones and carbonates.

The storage space available within a depleted oil field for CO_2 is dictated by multiple factors; the pore space made vacant after oil has been produced, the pore space occupied by introduced fluids (e.g. from water injection), invaded formation fluid if in contact with an aquifer and the potential compaction of the reservoir due to reduced reservoir pressure (if there has been no water injection to maintain pressure) during production (Hughes, 2009). Depleted oil fields will often be more structurally complex than saline aquifers and have smaller structures overall.

CO_2 injected into a depleted oil field will migrate vertically from the injection site towards the seal/cap where it is trapped. The CO_2 will then begin to migrate laterally as the plume equilibrates. This picture may be complicated by the presence of natural associated gas which evolved as the reservoir pressure declined during production of oil, leading to the reservoir containing a mix of oil, water, and saturated gas in varying percentages in different parts of the field. During the migration phase, CO_2 will be subject to the same multiple trapping mechanisms as saline aquifers, but will also include miscible phase trapping, whereby the injected CO_2 acts as a solvent dissolving in the remaining oil. As the mobilised oil is not being produced, the CO_2 becomes fixed in the reservoir.

Most oil fields will sit at a lower pressure at the end of production, compared to the virgin state. Sometimes significantly so. In general, this is positive for the capacity of the store as it means that a large volume of CO_2 can be injected before the pressure returns to virgin conditions, where the integrity of the seal rocks has previously been demonstrated. However, this can cause problems for injecting CO_2 that has been transported at high pressure in the early years of the CCS project when reservoir pressure is low. The pressure drop from the higher pressure pipeline into the lower pressure reservoir results in a significant temperature drop in and around the well bore that would need to be managed. In some oil fields, the reservoir pressure may have been maintained at a similar or marginally greater than virgin pressure. In this situation, water production wells may be needed as for saline aquifers. This carries a risk that the produced water may be contaminated with oil, posing a challenge for the surface facilities where the oil concentration in the produced fluid is too high to permit disposal direct into the sea, or local water course resulting in the water needed to be treated prior to disposal and the recovered oil disposed of in an environmentally sound manner.

Depleted oil fields will have existing wells drilled into the storage formation which creates potential leakage pathways for the stored CO_2 It is essential to consider and address the risk these wells pose to the permanent storage of injected CO_2 to minimize this risk. Evaluating and remediating oil production wells, if this is required, will incur additional costs in the development of the storage facility. Further discussion on this topic can be found in section 8.

T&S Downward Cost Pressures for Depleted Oil Fields

- Depleted oil fields have proven storage and seal characteristics, potentially reducing development and regulatory costs for the store.
- Existing dynamic information about the reservoir, caprock, internal architecture and fluid flow properties may allow the storage potential to be more accurately estimated.
- Existing infrastructure including wells, platforms, pipelines may be able to be reused.

T&S Upward Cost Pressures for Depleted Oil Fields

- CO_2 Injection in a lower pressure depleted field with a bottom hole pressure below 80barg may require additional conditioning of the CO_2, either by heating at, or close to, the wellhead or by using other technologies which increases well Capex and Opex over time, to avoid issues with flow assurance and thermal effects damaging the wells and reservoir.
- Potential for compaction of the reservoir to have already occurred during late life of oil production, which may lead to increased risk around storage volumes for the reservoir.
- Existing exploration/production wells in the store or neighbouring connected stores may not have been abandoned to a standard that is suitable for CO_2 containment, complicating the regulatory approvals process or leading to the need to repair or recomplete legacy hydrocarbon wells at significant cost. In some mature basins the task of locating and understanding the status of abandoned wells presents a challenge because of the lack of information recorded at the time and also the time elapsed since the wells were abandoned.

5.3 Depleted Gas Field

Depleted gas fields, like depleted oil fields, are fields which have undergone production to a point where further extraction is no longer deemed economically and/or technically feasible. Gas fields can occur both onshore and offshore at depths of hundreds to thousands of metres below ground level.

When injected into a depleted gas field, the CO_2 will sink from the injection site due to its higher density when compared with that of the residual methane, allowing for lateral migration as the CO_2 plume equilibrates. However, there may be a more complicated picture as natural gas reservoirs often contain liquid hydrocarbons, which have condensed out of the gas phase as the pressure declines during production, leading to a variable mix of gas, water, and saturated condensate.

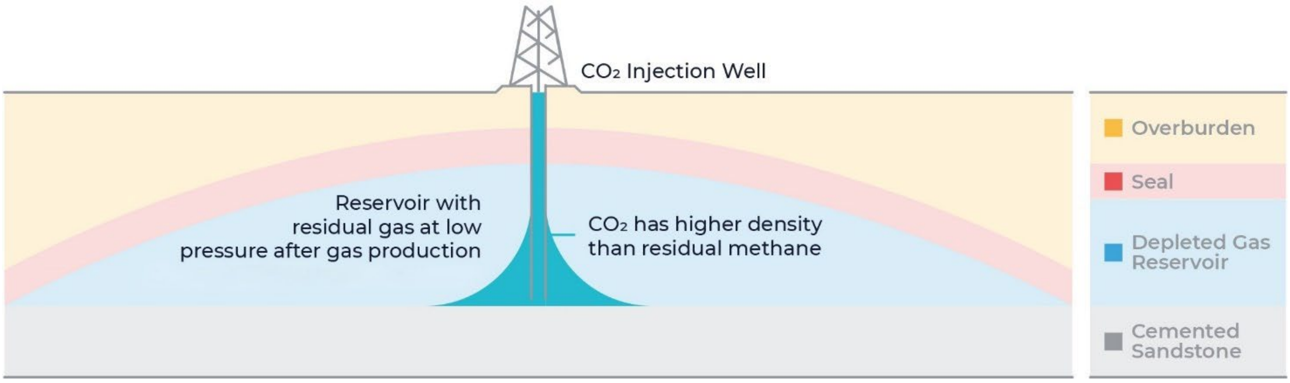

Figure 5.4 - A schematic representation of downward CO_2 plume migration within a depleted gas reservoir due to higher density CO_2 versus the density of residual methane.

The storage space available for CO_2 within a depleted gas field is dictated by several factors; the pore space made vacant after gas is produced, the pore space occupied by introduced fluids (e.g. from water sweeping), invaded formation fluid if in contact with an aquifer and the potential compaction of the reservoir due to reduced reservoir pressure (no water injection to maintain pressure) following production of gas (Hughes, 2009). The depleted gas field could then be refilled to its pre-production field pressure, due to the field having stored natural gas over geological timescales or it is possible it may be filled beyond this pressure, if the seal/cap failure envelope is sufficiently understood.

The CO_2, with time, will cover the base of the storage structure forming a CO_2 'cushion' due to its density relative to the residual hydrocarbon gas in the reservoir (Cao, et al., 2020). Over geological time, it is likely saline water will enter the system below the original gas-water contact, providing another potential source for trapping of CO_2 storage by dissolution.

Like depleted oil fields, depleted gas fields will also have existing wells drilled into storage formation which may create potential leakage pathways for the stored CO_2. It is essential to consider and address the risk these wells pose to the permanent storage of injected CO_2 as part of the storage site development process. Evaluating and remediating production wells, if it is ultimately deemed to be required, will incur additional costs in the development of the storage facility. Further discussion on this topic can be found in section 8.

T&S Downward Cost Pressures for Depleted Gas Fields

- Depleted gas fields have proven storage and seal characteristics potentially reducing development costs for the store.
- Existing dynamic information about the reservoir, caprock, internal architecture, and fluid flow properties, allows the storage potential to be more accurately estimated.
- Existing infrastructure including wells, platforms, and pipelines can potentially be reused.

T&S Upward Cost Pressures for Depleted Gas Fields

- CO_2 Injection in lower pressure depleted fields with a bottom hole pressure lower than approximately 80barg, although this is site specific, may require the CO_2 to be heated at or close to the wellhead or managed by increased well Capex and/or Opex spend over time, to avoid issues with flow assurance and thermal effects damaging the wells and reservoir.
- Possible integrity damage to the cap/sealing unit due to formation pressure changes within the reservoir rock through production of hydrocarbon gas, may lead to induced fracturing of the cap/sealing unit. This effect would generally increase project risks and development costs.
- Existing exploration/production wells in the store or neighbouring connected stores may not have been abandoned to a standard which is suitable for CO_2 containment, complicating the regulatory approvals process or leading to increased costs to repair or recomplete legacy hydrocarbon wells at significant cost.

5.4 Enhanced Oil Recovery

Oil fields will commonly undergo multiple production phases using various techniques to maximise production throughout their life. The phases can be grouped into primary, secondary, and tertiary phase production. During the primary phase production, the "virgin" reservoir pressure enables oil to flow from the production well, with rates falling as the pressure in the field declines. As oil is produced, the reservoir pressure will decrease to a point where secondary recovery is required to maximise the production potential of the field. Secondary phase production requires the artificial repressurisation of the reservoir by injecting water and/or natural gas. The injection wells can be strategically placed so the fluid drives the oil towards the production well. Tertiary phase production can then be implemented to further improve the recovery of hydrocarbons, of which one option is enhanced oil recovery (EOR).

In CO_2 EOR, CO_2 is injected into partially depleted oil reservoirs to improve the recovery factor of remaining oil (Figure 5.5). This works by both increasing the reservoir pressure and reducing the viscosity of the oil to improve flow rates (Melzer, 2012). It has been noted that the displacement of oil by CO_2 injection is reliant on the CO_2-oil mixture phase behaviour. Miscible CO_2 EOR is a process where injected CO_2 interacts with the oil in a reservoir. During this process, CO_2 pulls the lighter oil components into the CO_2 phase and CO_2 also condenses into the oil phase. This results in two fluids that mix well together, improving the oil's flow properties by reducing its viscosity and interfacial tension. The main goal is to extract more oil from the reservoir (Department of Energy & Climate Change, 2010).

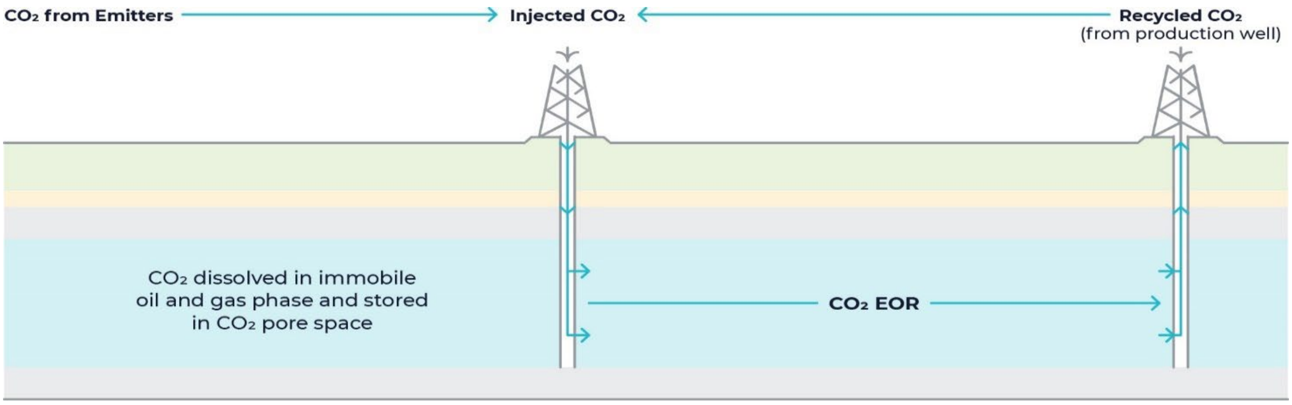

Figure 5.5 - Schematic illustration showing the injection of CO_2 for enhanced oil recovery, highlighting the miscible zone process.

Not all oil fields are suitable for CO_2 injection as oil composition, depth, temperature, and other reservoir characteristics significantly influence the effectiveness of this method (Melzer, 2012). The method by which production fluids; hydrocarbons, saline water and CO_2, are brought to surface facilities and handled, enables the separation and recapture of CO_2. Where EOR projects are designed to be closed loop systems, the recaptured CO_2 can be compressed and mixed with additional CO_2 and subsequently reinjected into the reservoir. It is the recapture and recycling of CO_2 that prevents it from being released into the atmosphere (Melzer, 2012). The need for additional CO_2 is the result of CO_2 retention within the reservoir post-injection, due to residual and solubility trapping. Historically the percentage of purchased CO_2 retained within the reservoir is noted as being as high as 90 – 95% (Department of Energy & Climate Change, 2010), with the losses occurring during the processing/recycling procedure and/or as a result of unconfined lateral migration away from the target zone.

Traditionally, the purpose of CO_2 EOR has been to produce more oil rather than to store CO_2. Purchasing CO_2 is a cost to EOR operations and therefore operators have focused on recycling CO_2 as much as possible. Moving a CO_2 EOR project towards the purpose of storing CO_2 while producing a small amount of additional oil, is something that can be considered as a field approaches the end of its life.

Historically, CO_2 EOR projects have been the main method by which CO_2 has been stored in the subsurface, therefore regional networks transporting CO_2 for this purpose have been in operation for decades. The regulations governing CCS vary from country to country and the treatment of CO_2 EOR as a storage solution is often viewed differently in different jurisdictions. It is included as a storage technique for the purposes of this study.

T&S Downward Cost Pressures for Enhanced Oil Recovery

- Increased productivity/profitability of a reservoir that may otherwise be at end of life. A successful CO_2 EOR programme may boost the total recoverable oil by an additional 3 - 5% of the original oil in place (National Petroleum Council, 2019). Both the oil produced, and the CO_2 stored can be viewed as revenue streams and the economics of the overall CCS project optimised as a result.
- Existing evidence base of reservoir operation.
- Potential to utilize existing facilities.

T&S Upward Cost Pressures for Enhanced Oil Recovery

- CO_2 EOR is often treated differently in different regions, with heightened regulatory or public interest leading to extended planning and regulatory involvement.
- Enhanced monitoring requirements to track emissions and prove "permanent storage" to satisfy legislation in some regions.

5.5 Novel Storage Options

The following sections describe novel options for CO_2 storage identified through a literature review. However, their applicability to large capacity CO_2 storage is widely considered in industry to be uncertain. For this study, these have been defined as 'novel' storage options due to their current technological development or commercial potential. The discussion below reflects their potential use in short to medium-term commercial-scale projects but accepts that the industry is developing rapidly, and the viability of these storage options may change in the short term.

5.5.1 Mineralogical Trapping (Flood basalts)

Flood basalts are thick extrusive igneous bodies, forming large deposits of basaltic rock. Typically flood basalts are low porosity, low permeability and have poor pore connectivity. If the basalt is highly fractured and a suitable cap rock is present, flood basalts have the potential to sequestrate CO_2 through mineralogical trapping.

The geochemical mechanism behind mineral trapping in basalt is a sequence of chemical reactions initiated by the partitioning of CO_2 into the reservoir's formation water. CO_2 and water react to form carbonic acid, which lowers the pH of the aqueous phase. The lower pH of the injected water causes minerals to react where the aqueous phase and the rock matrix are in contact with one another. The reactions result in the forming of solid materials, trapping the injected CO_2 as a solid in the formation (Postma, Bandilla, Peters, & Celia, 2022).

Researchers in Iceland, Europe, and the US were able to identify such a method in what has been termed the "Carbfix" process which is the name of both the technology and the company that has developed this process. In the Carbfix process, the CO_2 is dissolved into water, either before or during its injection into the subsurface, where the CO_2-charged water is denser than other reservoir fluids, and therefore naturally sinks to deeper levels. The slightly acidic water readily reacts with reservoir rocks, and carbonate minerals (calcite) are formed on a timescale that can take weeks to months, storing the CO_2 on a geological timescale.

Currently, there have been no large-scale projects identified that are in operation or development that are proposing this method of storage with only pilot studies (notably the Carbfix and the Wallula Basalt projects) being conducted to date. Both indicate mineralogical trapping of CO_2 within flood basalts to be a feasible storage technique, sequestering injected CO_2 by mineralisation.

5.5.2 Unmineable Coal Seams

Unmineable coal seams are seams that have been deemed as being too thin or too deep to be mined economically. Coal bed methane is a product of the coal bed gasification process. CO_2-enhanced coal bed methane production (CO_2-ECBM) is regarded as a promising method to mitigate the atmospheric release of CO_2 by utilizing deep-seated coal deposits. The way in which CO_2 is stored during CO_2-ECBM differs from other methods of CO_2 sequestration, in that the CO_2 is adsorbed to the coal within the seam.

Injected CO_2 is preferentially adsorbed onto the coal bed surface due to its greater affinity to coal (Busch, Gensterblum, & Krooss, 2003; Dutta, Harpalani, & Prusty, 2008), displacing the previously adsorbed methane. The injected CO_2 can also adsorb to 'free' organic macromolecular areas of coal unoccupied by methane/gas-hydrates.

Furthermore, as the injected CO_2 migrates through coal beds, CO_2 can be trapped in pores on the surface of the coal and in the water normally present within the coal beds.

This method of storage can potentially provide a source of methane as product of the process but capturing methane released during CO_2 injection may not be a straightforward activity, potentially negating some of the environmental benefits of storing the carbon in the first place, noting that methane has a higher global warming potential than CO_2.

5.5.3 Organic Shales

Organic shales are fine grained sedimentary rocks rich in organic matter containing kerogen, which is the source rock for hydrocarbons. Organic shale reservoirs differ from conventional reservoirs in that the shale acts as the source, reservoir, and trap. The injection of CO_2 into organic shales aims to simultaneously sequester CO_2 while also enhancing the recovery of stored gas (methane).

In a similar fashion to CO_2-ECBM, it is proposed that CO_2 would be injected into organic shale formations. The injected CO_2 is trapped in the adsorbed phase to the surface of organic matter (kerogen)/clays (Levine, et al., 2016). With time, the trapped CO_2 can undergo chemical dissolution into the formation saline water, forming a carbonic acid. Reactions between the acidified formation saline water and minerals contained within the shale result in mineral precipitation, providing long-term storage.

The injection of CO_2 into organic shales can facilitate the production of new/additional trapped hydrocarbons, providing an economic upside when sequestering CO_2 and providing a source of income for projects, i.e. equivalent to CO_2 EOR in conventional oil fields. However, this storage option is presently relatively untested, and the complex heterogeneity often observed in shale formations could limit understanding of the formation pore system and microstructures. In turn, this could limit the understanding of gas migration pathways, pore connectivity and CO_2 /shale interactions. Concerns around the impact of CO_2 on the mechanical properties of the shale could also raise questions about the longer-term sealing efficiency of the storage structure.

6 TASK 1 - COMBINED TRANSPORT AND STORAGE SYSTEMS ARCHITECTURE

The options for T&S elements are relatively limited as noted in the section above, with a finite number currently being developed or available for each part of the system. Following typical design methods and techniques, system developers are not normally constrained by the technical challenges of combining the T&S archetypes and each of the options are broadly interchangeable. For example, a liquid shipping solution can be paired with any of the storage options and aquifers can be supplied with CO_2 by any transport method. Multiple transport archetypes can also be linked together to move CO_2 from the emitter to the store.

The requirement and location of compression systems in T&S networks varies, depending on the emitter arrangements, length of transport route, store operating pressure, local regulations, and other factors. It is noted that several variations of each system archetype could be introduced in this section, given the various potential location of compressors on a network. Two comparable systems are the UK's Northern Endurance Partnership (NEP) / East Coast Cluster and Viking projects which are both subject to the same regulatory framework. NEP's T&S pipeline system collects gaseous CO_2 onshore from emitters and compresses it into a dense phase gas. The Viking T&S project follows a different design that requires emitters to supply dense phase gas CO_2 directly to the onshore gathering pipeline and the pipeline T&S system does not need to have its own compression or pumping equipment. Generating a large number of archetypes to illustrate all of the potential variations would bring limited additional value to the discussion in this report. To limit the archetypes reported, the location of compressors in each archetype is briefly discussed, however, a larger focus is placed on the high-level arrangement of the archetype. Where appropriate, the issue of system operating pressures and how they influence T&S life of project costs are discussed in Task 3.

The specification of CO_2 is important and further discussion on this topic can be found in section 8 of this report. Typically, the CO_2 specification is set by the T&S operator, and the conditioning equipment needed to meet these specifications is operated by the emitter. However, this can vary based on the specific project, including factors such as the transport technology, store type, and commercial agreements between the involved parties. For the purpose of this section, it is assumed that the emitter supplies CO_2 that is compliant with the T&S system specifications and no further conditioning is required.

While it is important to note that some groupings and pairings of T&S options are more efficient than others, it is valid to consider the storage options as being transport method agnostic and other drivers such as: location of the emitter and store, the topography of the region, location of waterbodies, the extent of environmentally protected areas or population density in the region, will ultimately drive the design of the project. With this principle applied, the following sections set out the typical T&S system designs that are being considered by projects under development or in operation. The following sections draw on the author’s technical knowledge and experience in designing and operating analogous systems in CCS and other sectors, as well as publicly available information on the proposed projects that are discussed in this report.

6.1 Single Emitter with Pipeline to Store

Figure 6.1 - Single Emitter with a pipeline to local store

A CCS value chain with a single emitter feeding into a pipeline, before flowing to a store (Figure 6.1). This configuration is utilized in the industry for both onshore and offshore storage sites.

In this archetype, the emitter must shoulder the Capex and Opex of all the equipment in the value chain, from capture, through to transport including compression and storage. The operation of the system is tied to the reliability of the emitter's capture plant and the reliability of the store. This type of system would typically have limited intermediate storage capacity, and limited time to resolve operational issues at the emitter plant or storage site.

Many of the currently operating or previous demonstration projects follow this model, with some projects in North America utilizing the CO_2 for EOR.

6.2 Onshore Gathering Pipeline Network to Store

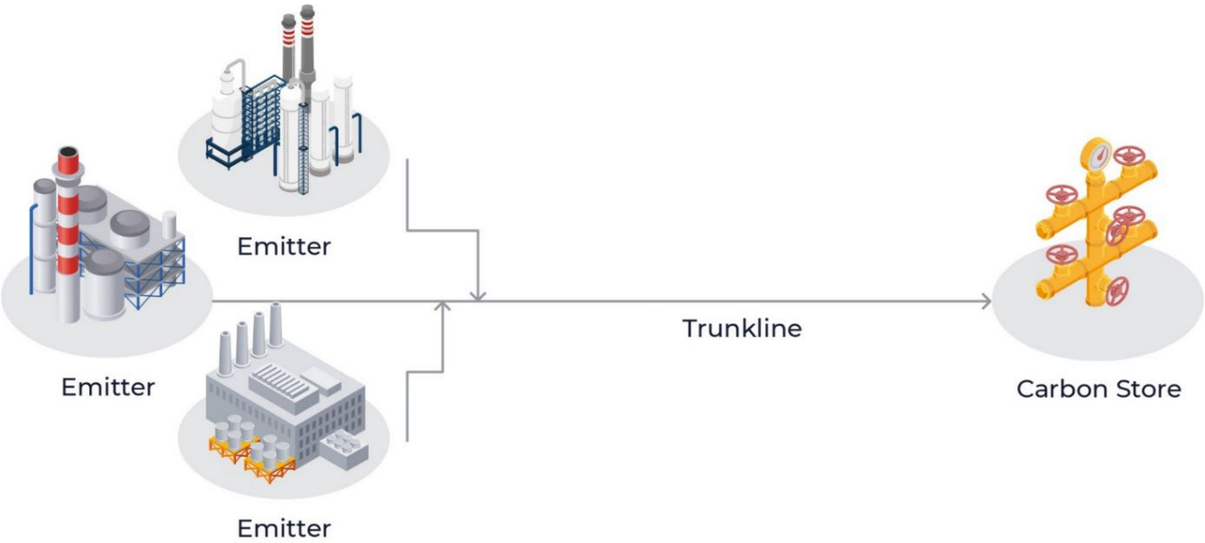

Figure 6.2 - Onshore gathering pipeline network to store

As shown in Figure 6.2, this archetype aggregates CO_2 produced by multiple emitters, with the CO_2 transported in a common pipeline to a store. The location of emitters in this archetype differs by region. In some European systems under development, emissions are collected from a small geographic area of 10s of kms, the "cluster" approach. Conversely, in North America, operational systems and others in development collect emissions from emitters dispersed along pipeline systems that span hundreds of kms. The infrastructure can be utilized for both onshore and offshore storage sites, with the CO_2 being transported in the gaseous phase for short distances or, more typically, as a dense phase gas for longer distances. Compression would normally be required between the outlet of the emitter capture plants and the entry point to the pipeline. Intermediate compression stations may also be required to boost the pressure further before entry into the common pipeline to the store depending on the length of pipeline or general system operating pressure.

In this archetype, the emitters share the Capex and Opex of the pipeline and store and can share some of the cost of compression if it is needed for the common pipeline section. Depending on the system design, this approach can begin to realise economies of scale for the T&S elements and reduce lifetime operating costs.

The operation of the system is similar to existing hydrocarbon pipeline gathering systems. However, interdependencies between the emitters, pipelines, and the ability to use the pipeline volume to smooth out variations in flow exist that can have positive and negative effects on the operating cost of the system. For example, consideration of the variability in flowrate of CO_2 provided by emitters is important to ensure a consistent injection rate at the storage site, which would in turn improve the availability of the store and consequently the overall system availability. Having a high availability within the system will ultimately increase the amount of CO_2 stored, and in turn lower the overall cost of capture and storage for all the emitters.

Many of the current projects being considered in all regions follow this archetype, driven by the potential for economies of scale and the existing geography of the emitter base.

6.3 Multi Nodal Liquid Transport to a Single Pipeline and Store

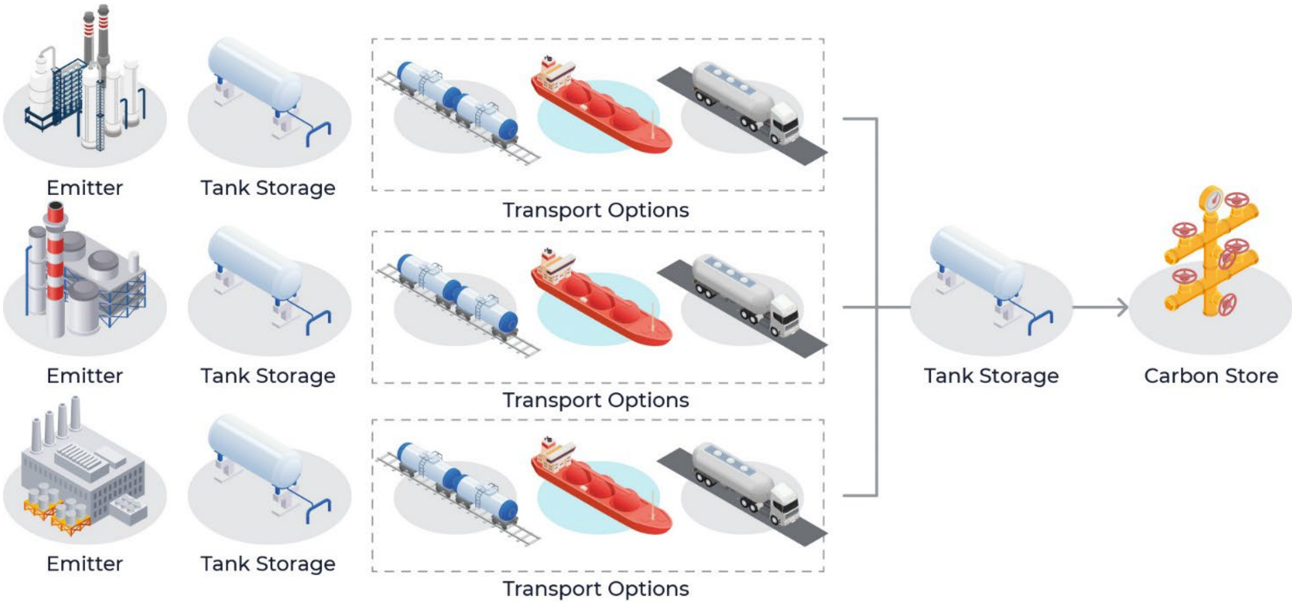

Figure 6.3 - Multiple emitters with dedicated transport to storage, prior to local store

As shown in Figure 6.3, this archetype collects liquid CO_2 transported in tanks from multiple disparate emitters in a common onshore hub. The CO_2 is held in intermediate storage at the hub, before being transported to the wells via a pipeline and pumps for permanent storage. This approach allows emitters to share the costs associated with the intermediate storage, pipeline, pumps and well storage equipment. There may also be some synergies with the liquid transport equipment depending on the location of the emitters and central hub.

This type of system requires increased levels of equipment at emitter locations, to liquefy and store the CO_2 before it is moved by road, rail, or ship to the central hub, where storage is additionally required to efficiently use the next step transport methods.

As noted in the section above, it is generally accepted that moving gases by tank is more expensive than by pipeline over shorter distances if the geography allows. This archetype is likely to suit systems where the store is remote from the emitters or where pipelines are difficult to install due to local factors including topography or population density.

This archetype has several operational trade-offs with the provision of liquid storage at the central hub allowing for stable and planned injection rate changes at the wells, further supporting well availability. The logistical challenges of delivering the liquid to the hub, including bad weather, creates different challenges for the operations teams at both the emitter and storage locations.

6.4 Onshore Gathering Pipeline System from Multiple Emitters with Aggregated Ship/Rail/Road Liquid Transport to a Hub and Pipeline to Store

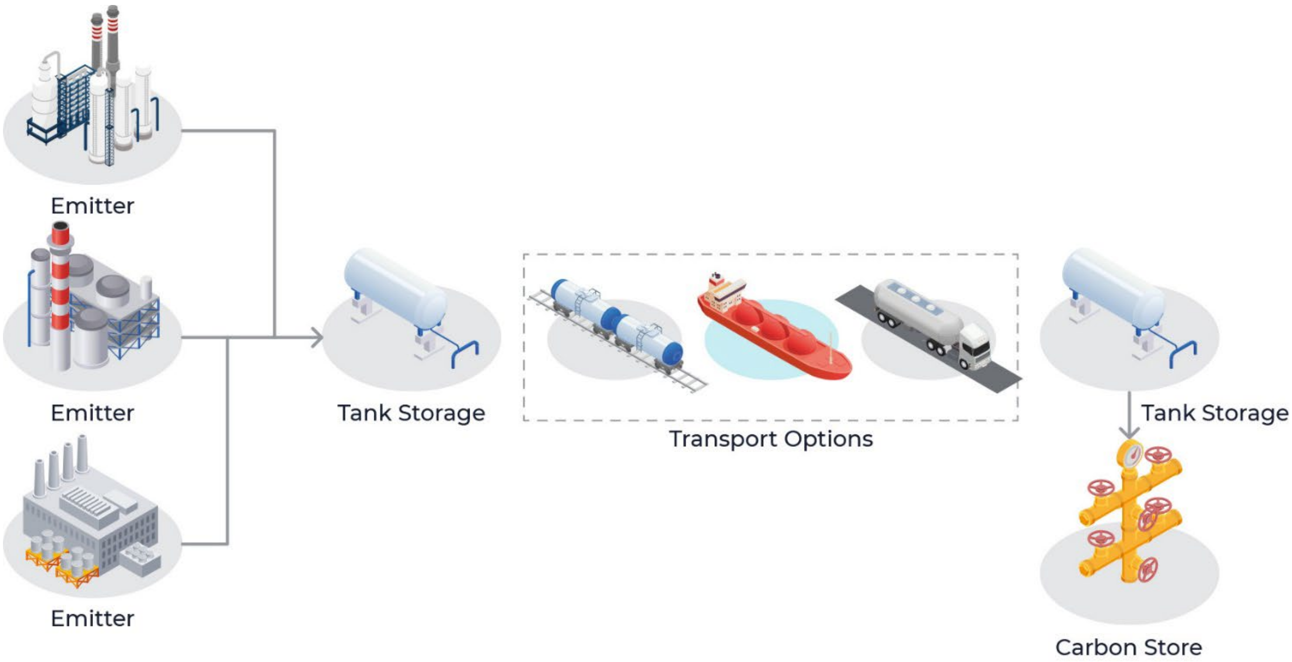

Figure 6.4 - Onshore pipeline and transport system from local emitters to onshore hub, prior to store

As in Figure 6.4, this archetype collects CO_2 from onshore emitters by a common pipeline. Emitters will require some form of dedicated compression or use of energy if it is an integrated process in the capture plant to move CO_2 from their location to the shared liquefaction hub. The CO_2 is then liquefied at a central hub and held in intermediate storage before being moved by tank (road, rail, or ship) to the storage site. At the storage hub, the liquid CO_2 is held in intermediate storage tanks before being pumped to the wells by pipeline, before being permanently stored.

This approach allows remote emitters to share the costs across the T&S chain, allowing economies of scale to be realised in liquefaction, intermediate storage, and liquid transport elements of the chain. This approach would be attractive for industrial regions that have co-located emitters but do not have pipeline access to a store.

This archetype has several operational trade-offs with the provision of liquid storage at the central hub allowing for stable and planned injection rate changes at the wells, further supporting well availability. Logistical challenges of delivering the liquid to the hub including bad weather, creates different challenges for the operations teams at both the emitter and storage locations.

6.5 Onshore Gathering Pipeline Emitter Network with Multi Nodal Liquid Transport and Pipeline to Store

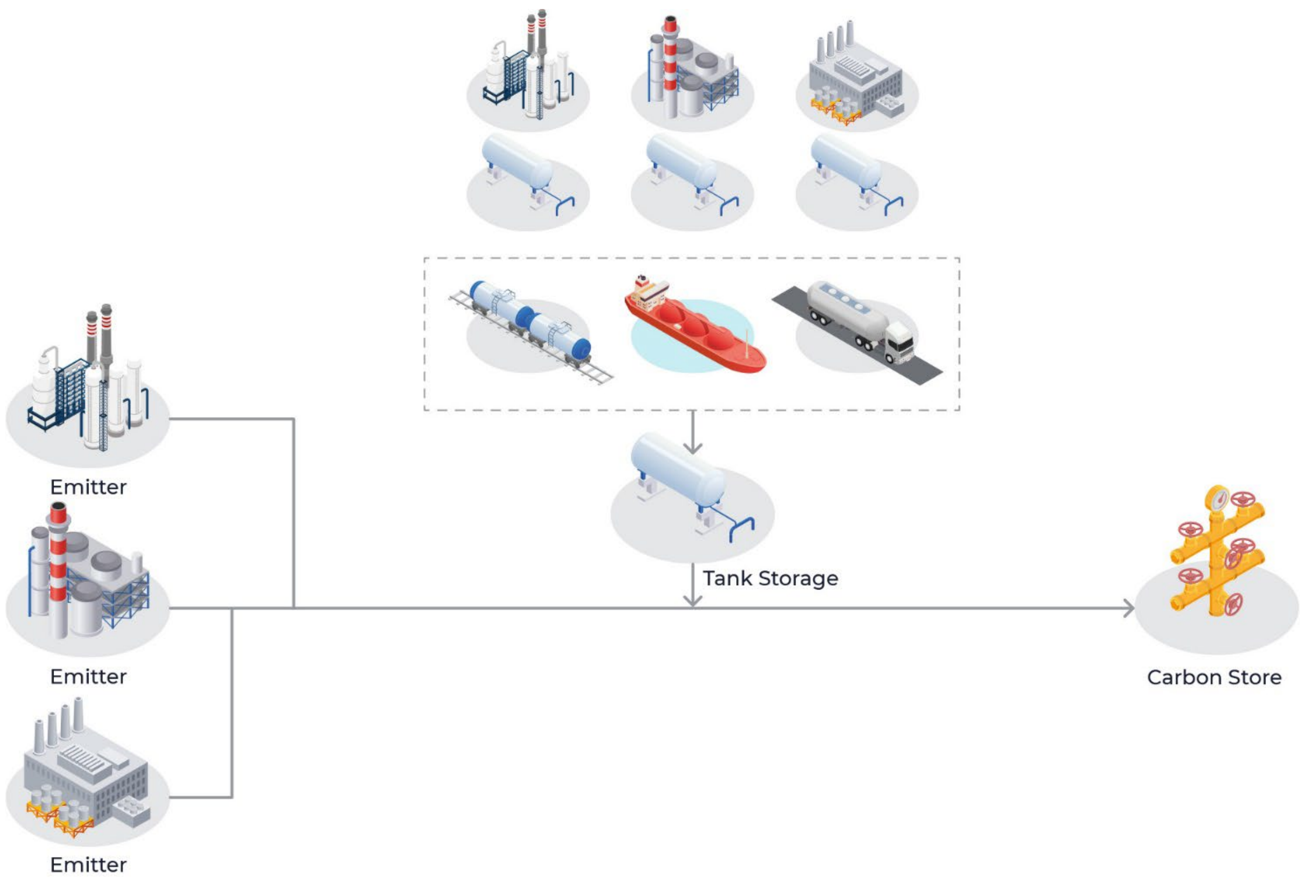

Figure 6.5 - Onshore gathering pipeline with multi-nodal liquid shipping network

Combining an onshore gathering network with liquid transport by ship, rail or road is possibly the most complex of the identified archetypes in terms of project construction and operation (Figure 6.5). This archetype allows both pipeline served emitters and remote emitters to share common transport infrastructure, including pipeline compressors if required and also pumps as well as storage infrastructure.

The provision of pipeline as well as liquid transport of CO_2 provides greater flexibility to smooth out flow variations to the well and store arising from either logistic delays or availability problems. For example, if a pipeline emitter flow is interrupted, it would be possible to increase flow from stored liquid while the pipeline emitter returns to service.

6.6 Summary

The variety of system archetypes is extensive, with the placement of emitters, compression systems, and storage facilities being crucial to system design. Noting this fact, it is evident that each system, like all infrastructure projects, needs to be tailored to the specific requirements of its users, reflect the local geography as well as the availability of storage and location of emitters within the region. Despite this, certain trends are emerging within the industry. Historically, the CCS value chain was perceived as capture, transport, and storage from a single source to a single store. However, numerous prominent projects now show that the industry is evolving towards 'CCS clusters' or hubs, where multiple emitters connect to shared transportation infrastructure leading to one or more shared storage sites. The aforementioned archetypes indicate that substantial economies of scale can be achieved in both T&S components of a project, reflecting this shift in approach.

7 TASK 2 - CASE STUDIES TRENDS AND INSIGHT

CCS T&S costs have been the subject of investigations in academia and the private sector for an extended period, with a large range of papers and publications on the topic residing in the public domain.

The purpose of this section of the report is to identify useful and recent sources of data from projects and highlight any trends identified for existing and planned projects.

7.1 Case Study Methodology

This analysis aims to provide clarity on the quality of information in the public domain that can be used by stakeholders. Given the rapid expansion of projects within the global CCS industry, this review focuses on larger and more developed projects in regions and specific countries, to understand what information is available and where possible, to breakdown input factors and assumptions involved in developing cost data. Where possible, the case studies provide the following:

- Discussion about the general status of CCS in the region.
- Highlight significant projects in the region.
- Highlight high quality cost information linked to the significant projects.
- Highlight any other sources of information published by linked government or non-government agencies.
- Summarise and sort the high-quality sources of data to identify trends to be addressed in Task 3.

To allow the sources to be easily tracked, cited costs have been reported in the currency quoted in the literature. Where helpful to allow costs to be compared, they have been converted to GBP using an average 2024 currency conversion rate.

Unless explicitly mentioned, costs for individual projects have not been repeated within this report, as the assumptions and methodologies used to generate these costs are not always easily identified and can be misinterpreted. Instead, an appropriate link to each source has been provided.

It should be noted that a range of limitations were identified within this methodology process, as discussed below.

7.1.1 In Scope Publications

The Global CCS Institute (GCCSI) publishes an annual list of projects in its “Global Status of CCS Report” series (Global CCS Institute, 2023). The industry considers this report as a reliable source for summarizing global CCS projects. The report groups projects by maturity, from those at an early development phase, to those in construction and in operation.

The groupings in the GCCSI project list broadly reflect likely maturity of costs for the projects, with “In Operation” projects having the most mature Capex and Opex estimates, whereas early phase projects are likely to have the widest range in accuracy of cost estimates given their early project maturity. The project status definitions from the GCCSI Annual Global Status of CCS report are as follows:

- Early Development: The facility is completing or has completed a pre-feasibility or feasibility study.
- Advanced Development: The facility is completing or has completed a front end engineering design (FEED). For storage sites, the proponent is completing a submission or has submitted a field development plan or equivalent to regulators.
- In Construction: A positive final investment decision (FID) has been made.
- Operational CO_2 is actively captured, transported, and stored.

It is understood that the developers self-report the status of the projects based on this guidance. As a result, there will be variations in the status of the projects.

To narrow the scope specifically to projects with mature and reliable cost information, the GCCSI project list was filtered using available information from a range of sources. The highlighted projects identified within this review have met the following combined criteria:

- Projects in operation, construction or thought to be relatively mature in development.
- Projects with a throughput of more than approximately 0.9MTPA, i.e. the typical capacity of a single injection well in a large-scale project.
- Projects in the regions identified in the scope, North America, Europe, and Asia (including Australia).

In tandem with the prioritisation of projects, the study has also focused on projects with direct government funding, as it is becoming a common requirement for developers to publish detailed costing information as a condition of the provided funding. Government and agency publications that report on CCS projects were also included in the review.

The analysis of the GCCSI's Annual Global Status of CCS Report 2023 in Table 7.1 shows 68 projects which meet the above criteria at the time of writing of this report. These projects are predominately in an advanced development stage (Global CCS Institute, 2023).

GCCSI PROJECT STATUS	PROJECTS
Advanced Development	46
In Construction	10
Operational	12

Table 7.1 - Summary of project status from the Global CCS Institute Annual Global Status of CCS Report. Projects filtered to highlight mature projects.

From the GCCSI Annual Global Status of CCS report, the top five countries by numbers of projects are the USA, Canada, United Kingdom, China and Japan, with the majority of projects currently within the Advanced Development stage.

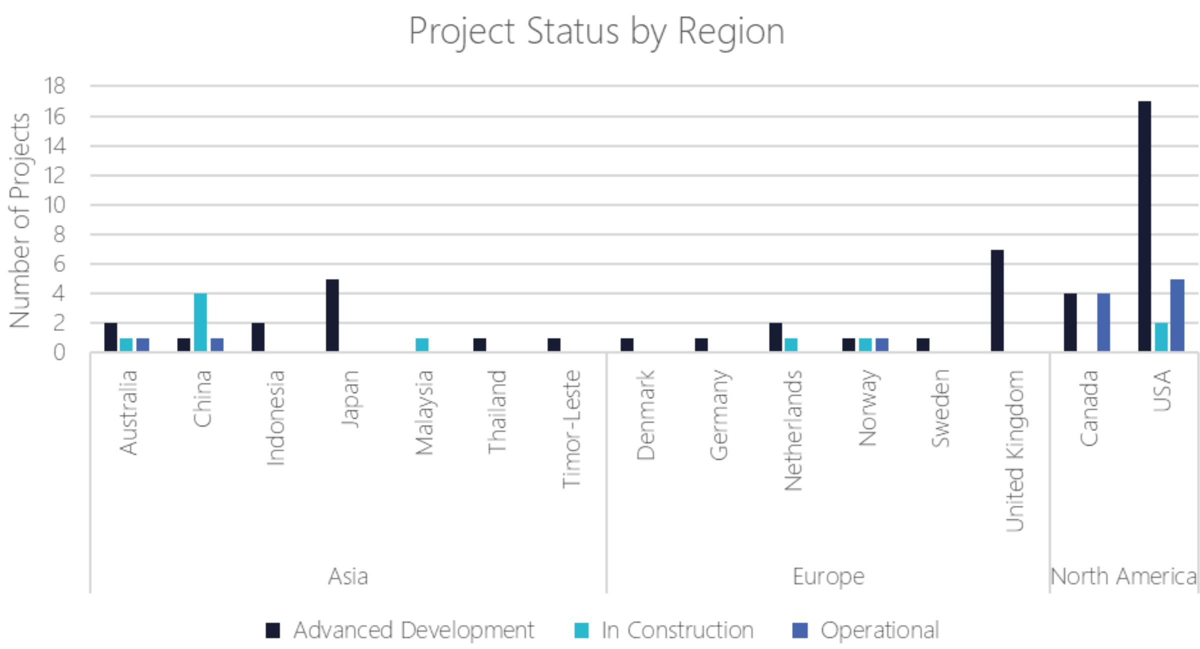

Figure 7.1 - CCS project status by region (Global CCS Institute, 2023)

7.1.2 Limitations of the Case Study Review

When undertaking the case study literature review, there are limitations on the data presented. As such, it is acknowledged that this report may exclude detailed project lifecycle costing information that resides in the public domain but is not easily accessible due to the following limitations:

- Project scope: The project scope defined the case study research areas to include Europe, North America, and Asia (including Australia). Given the significant increase in the number of CCUS and CCS projects, the largest and most developed projects with published costs were prioritized for review. As such, some countries and projects may not have been directly addressed. However, it is acknowledged that the CCS industry is developing rapidly, and with it, the number of documents in the public domain is also increasing.
- Translation constraints: Given the international scope of review, limitations were encountered in the translation of project documentation. Consequently, if project cost information was not presented in English, we were unable to easily conduct a comprehensive and detailed analysis of the project at this time.
- Accessibility: Presently, there is no consistent nor internationally accepted process to publish and access CCS costing information. Different governments and industry sources document project updates and costs in different ways, which posed constraints in obtaining this information. There were many occurrences where this information was not easily accessible via a government website nor through a single source from project investors.

- **Limited requirements to publish costs:** A limited number of governments have tied funding provisions to the requirement to report project costs to the public. If the project is predominately funded and driven by the private sector, there is limited incentive or requirement to share costing data, which often has been created specifically for the project at significant cost.
- **Computer based modelling tools:** The study terms of reference requested that scenario-based computer modelling tools used to estimate T&S costs were included in the scope. It is known that tools used to produce cost estimates for oil & gas type projects are currently used or can be adapted for T&S projects. Examples of this type of tool include S&P Que$tor, CO_2 EOR Screener tools, Aspen's Process Simulator costing tools, as well as bespoke developer or contractor estimating tools. Network planning tools, which have been developed to aid infrastructure planning decisions for CCS T&S systems such as Carbon Solutions SimCCSpro, SINTEFS iCCS and CO_2LOS tools, and Xodus' own European and APAC Market modelling tools are also being actively used in the sector. These types of tools are however not publicly available and will contain proprietary data making it difficult to access, review or critique the output and as a result these prominent but proprietary tools are only be discussed at a high level.

  Where credible estimating tools or details about the tools are publicly available, such as those produced by government supported agencies in Norway or the US, they are highlighted and discussed.

7.2 Europe

This review has identified that Norway, The Netherlands, The United Kingdom, and Denmark currently have the most mature and developed large scale CCS projects in Europe. This can be attributed to the proximity of each country to the North Sea, which has a known storage capacity, general industry appetite and government support, with the latter leading to more complete costing information being published.

7.2.1 UK

The UK has announced plans to initially support four carbon capture clusters, aligned with the government's ambition to decarbonise industry and power. This is known as the Track Sequencing process. Each cluster has completed various levels of studies, with knowledge sharing reports containing cost data publicly available. Two projects, HyNet and the East Coast Cluster, are known to be progressing towards FID and will be supported by government funding via both an emitter subsidy scheme and via a Regulated Asset Base (RAB) revenue guarantee scheme. The below section provides a high-level summary of the "Track Cluster" projects, including any published cost analysis data.

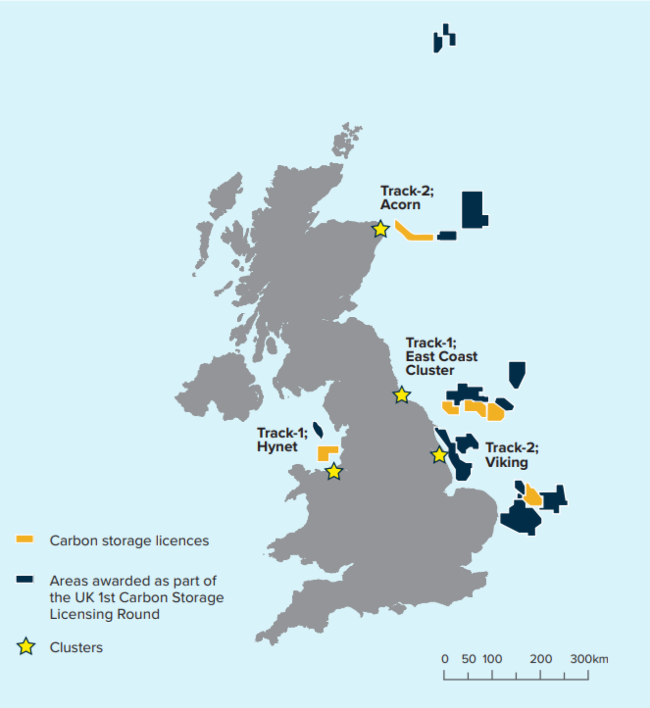

Figure 7.2 - United Kingdom carbon capture and storage clusters (Department of Energy Security & Net Zero, 2023)

HyNet

The HyNet cluster (HyNet North West, 2024), an onshore gathering pipeline network to offshore store located in Northwest England and North Wales, plans to use existing oil and gas infrastructure in the Liverpool Bay Area supplemented with new infrastructure including a compressor station. Following earlier feasibility studies, an industry consortium was formed to deliver a pre-FEED level study (HyNet North West, 2020) focused on the full chain CCUS infrastructure element of the HyNet project.

The study developed AACE Level 4 cost estimates (Capex and Opex) for the various elements of the T&S infrastructure. The cost estimates are specific to the Liverpool Bay existing assets, taking into consideration the modifications required to repurpose the facilities for CO_2 injection. As a sensitivity, the project estimated costs for road transport options, instead of pipelines. Full details of the costing can be found in the pre-FEED level study (HyNet North West, 2020).

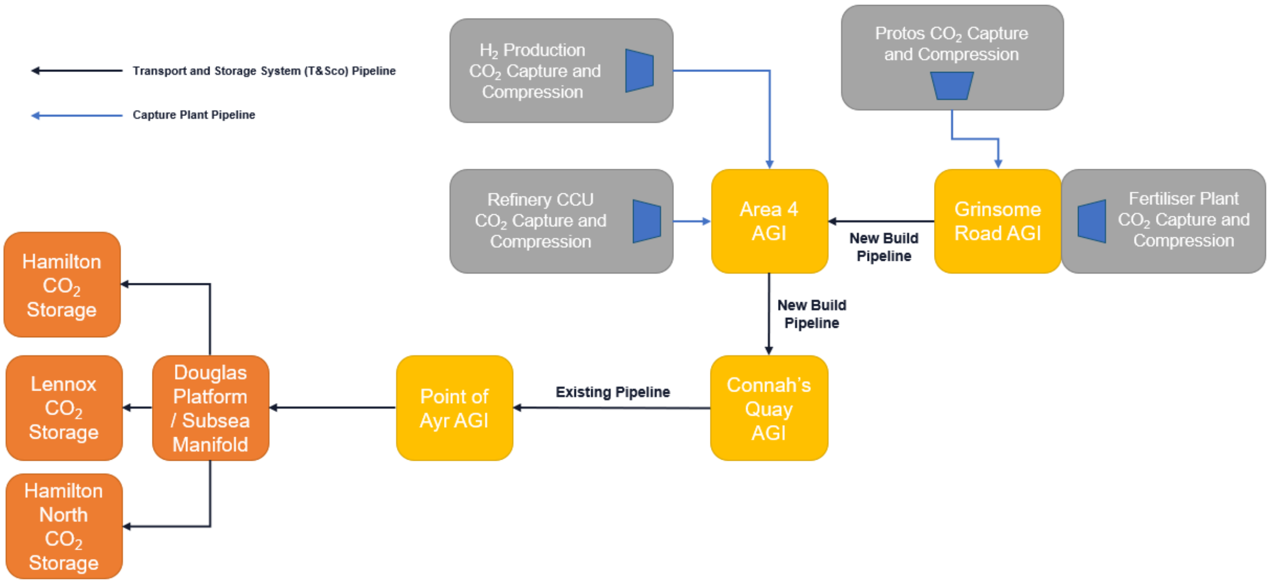

Figure 7.3 - HyNet full chain CCUS block diagram (HyNet North West, 2020)

An estimate of the system T&S tariff is also included in the report, covering the different operating phases of the project. The output of this work is shown in the figure below. The estimate demonstrates that the cost can vary dramatically depending on the flowrate through the system.

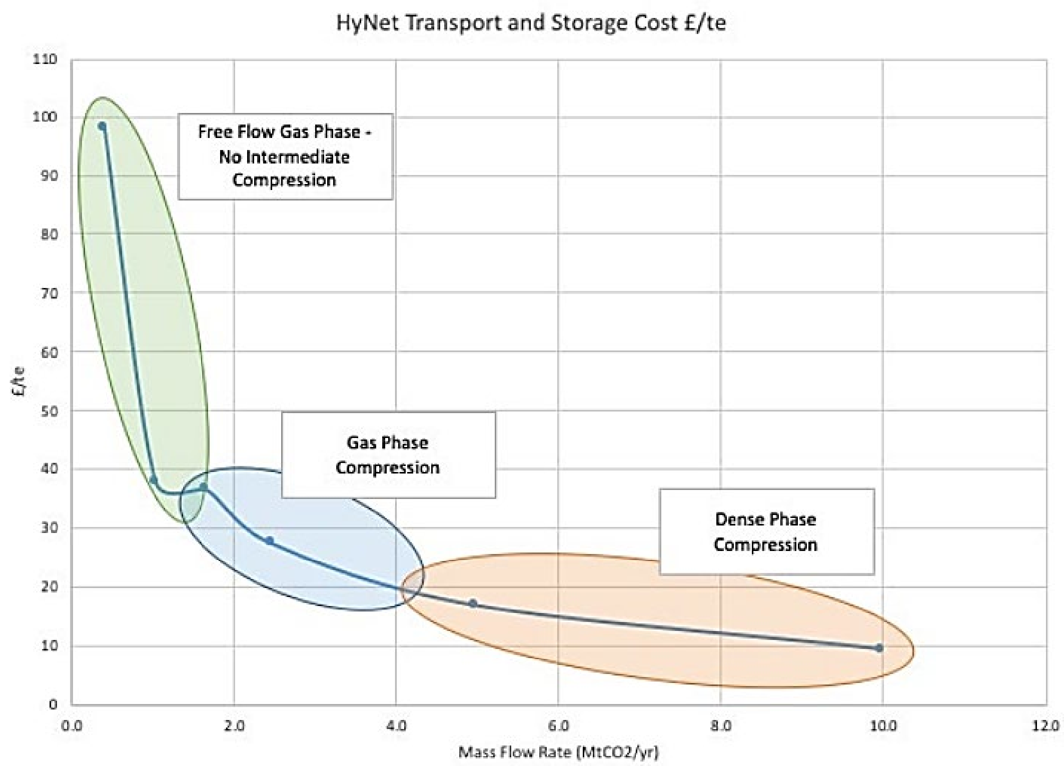

Figure 7.4 - HyNet T&S cost £/tonne CO_2 (HyNet North West, 2020)

Northern Endurance Partnership (NEP) / East Coast Cluster

The Northern Endurance Partnership (NEP) is an onshore pipeline gathering network to offshore store. It will provide the common onshore/offshore T&S infrastructure to enable the decarbonisation of the Teesside and Humber industrial clusters and form the East Coast Cluster (Net Zero Teesside, 2024). The store is a saline aquifer with a maximum rate of ~ 18MTPA over 25 years and will require saline water pressure management. Phase 1 of the project aims to deliver storage capacity of 4MTPA, with a transport infrastructure capacity of 18MTPA. There is no existing infrastructure and onshore gathering facilities, compression systems, offshore pipelines, plus offshore injection facilities, will need to be constructed. Phase 1 of the project would install a 28" 142km pipeline to Teesside rated for 10MTPA. A second, 101km, pipeline will be required for the Humber cluster rated for 17MTPA. A subsea distributed layout with 5 injection wells and 1 monitoring well is proposed for injection into the aquifer for Phase 1.

Drilling and completion costs were generated and published in 2022 by considering typical and recent North Sea rig and service rates, as well as typical costs for tangibles and rig verification (Department for Business, Energy & Industrial Strategy, 2022). These individual rates and costs have been rolled up into an overall daily rate that covers the duration of the well campaign. Offshore pipeline cost estimates have not been detailed at this stage. Life of project T&S costs or costs associated with the onshore or offshore pipelines are not included in this work.

Acorn

The Acorn project (Acorn, 2024), an onshore pipeline gathering network to offshore store, is a full chain CCS scheme in Scotland. Emission will be supplied by "the Scottish Cluster" which is a collection of existing and proposed industrial, power and hydrogen businesses in the Central Belt and North East of Scotland. The project plans to make use of existing onshore and offshore infrastructure, including a 280km repurposed 36" onshore gas transmission pipeline (SCCS Database).

The pipeline system has capacity of up to 20MTPA, with Phase 1 of the project focusing on capturing 345kTPA from the St Fergus Gas Terminal. Phase 2 of the project would include production of blue hydrogen at the St Fergus Gas Terminal, a link to the Scottish Cluster by repurposing the 36" Feeder 10 onshore pipeline gas transmission pipeline, and an option for the import of CO_2.

Acorn CCS Phase 1 is a demonstration of scale and is currently in the design stage. A feasibility study has been completed for the overall CCS scheme. The latest publicly published material (UK Government, 2021) does not include cost estimates nor commercial details.

An earlier CCS scheme, Peterhead CCS, relied on some of the same infrastructure including the Goldeneye pipeline and platform, however with a smaller capacity of up to 1MTPA. A FEED was completed by Shell in 2015, but the project ultimately did not go ahead due to the withdrawal of government funding. Cost estimates were prepared by Shell throughout the various previous phases of the project over an extended period of time (Shell UK Limited , 2015). Commercial, Project Management and Lessons Learned knowledge gathered from the Peterhead and White Rose (Yorkshire) Carbon Capture & Storage projects are publicly available (Department of Energy & Climate Change, 2016). The cost data published from these earlier projects will be significantly affected by cost inflation, as seen across the energy industry in recent years. Given the projects have been superseded and the scope of the study aims to review recent information rather than revisiting older data, they are not discussed further within this study.

Viking CCS

Viking CCS (previously V Net Zero), an onshore pipeline gathering network to offshore store, targets industrial emitters located in the Humber, Lincolnshire, and Nottinghamshire regions (Harbour Energy, 2023). The project will utilize a combination of existing and new infrastructure, with plans to redevelop the pipelines associated with the former Theddlethorpe Gas Terminal for CO_2 use. The system utilizes emitter compression systems therefore the T&S system does not have a compressor station. No cost estimates have been made publicly available for the project.

7.2.2 Denmark

The CCS industry in Denmark is progressing rapidly, driven by governmental support. The Danish government has established two subsidy funds, the CCUS Fund and the NECCS Fund, to support the deployment of CCS technology and achieve significant greenhouse gas reductions by 2030. Additionally, Denmark is actively developing infrastructure for CO_2 T&S in collaboration with neighbouring countries. Project information and cost data from the country is listed below.

Greensand

Project Greensand is a CO_2 T&S project, located offshore Denmark. The project completed the pilot phase with 4,100 tonnes of CO_2 from the Ineos Oxide factory in Belgium shipped to the Nini West platform and injected in the Nini West reservoir. The next commercial project phase, with 0.4 MTPA in storage capacity, is expected to be operational from the start of 2026. The full-scale project, mature by 2030, will store up to 1.5MTPA of CO_2 in the Nini main Field with CO_2 shipped from across the region. Beyond 2030, up to 8MTPA CO_2 will be shipped and stored in the depleted fields of the Greensand area.

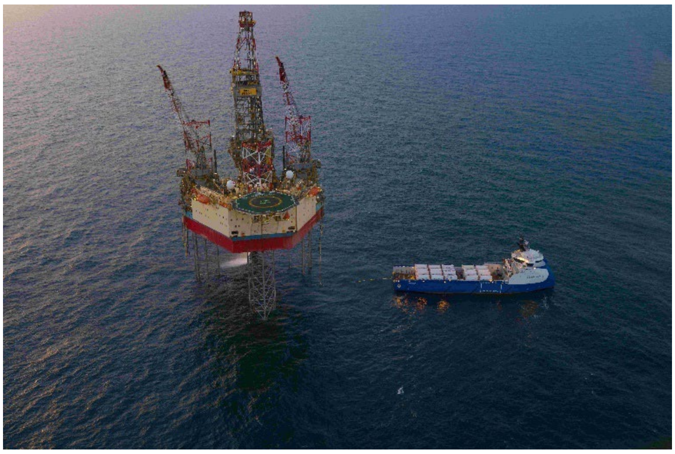

Figure 7.5 - Project Greensand pilot project platform (Project Greensand, 2024)

Detailed cost estimates for the project have not been disclosed for the Greensands project. However, there are several resources available for cost estimation in the Danish market:

Technology Catalogue for Carbon Capture, Transport, and Storage:

This catalogue (Danish Energy Agency and Energinet, 2024) covers data regarding energy technologies designed for CCS, predominately for those that are relevant for the Danish industry. Included within the catalogue are details on costs associated with T&S of CO_2, as well as estimates of energy consumption.

Costs within the report are largely taken from literature or from estimation tools used by the authors and include:

- Liquefaction costs
- Transportation costs - pipeline (onshore and offshore) vs ship
- Road transport costs
- Capex for onshore intermediate storage
- Storage costs
- Consideration of financing costs and capacity

The technology catalogue is a useful summary of published information drawn from a wide range of sources including documents cited elsewhere in this report. Several concepts linked to potential storage projects have also been developed in the report, with T&S tariffs reported alongside the capacity and equipment assumptions. The potential accuracy of the tariff data published is discussed but no range has been stated in the report. Given the nature of the publication, and the accuracy of the cost estimates have not been disclosed for verification, Xodus considers the available published costs to be at an appraise phase level.

Assessment of the Market Potential for CO_2 Storage in Denmark Report:

The report (Danish Energy Agency, 2021) assesses whether, and to what extent, there is market potential for storing CO_2 exports from Northern European countries in Denmark, along with Denmark's competitiveness as a potential European CO_2 storage provider. The report provides an overview of the CCS projects within Northern Europe, as well as an economic assessment of the business case for storage of CO_2 in Denmark.

7.2.3 Netherlands

The CCS industry in the Netherlands is developed and supported by the government SDE++ subsidy scheme, which will support emitters and T&S schemes. The Dutch government has recognized CCS as a crucial component of its climate policy, aiming to significantly reduce CO_2 emissions. Several projects are underway, including the Porthos project which is under construction, and the Aramis project, which is progressing towards FID.

Porthos

The Porthos CCS project is an onshore gathering pipeline emitter network and pipeline to store. It is initially a 2.5MTPA T&S project with the onshore gathering network design for 10 MTPA but the store limited to 2.5MTPA. It consists of a new 30km onshore 42" pipeline (in an existing pipeline corridor), a compression station, a new 22km offshore 16" pipeline, and storage in a depleted gas field using a repurposed platform in the P-18 block (Porthos, 2023). The project has taken its Final Investment Decision (FID) in 2023.

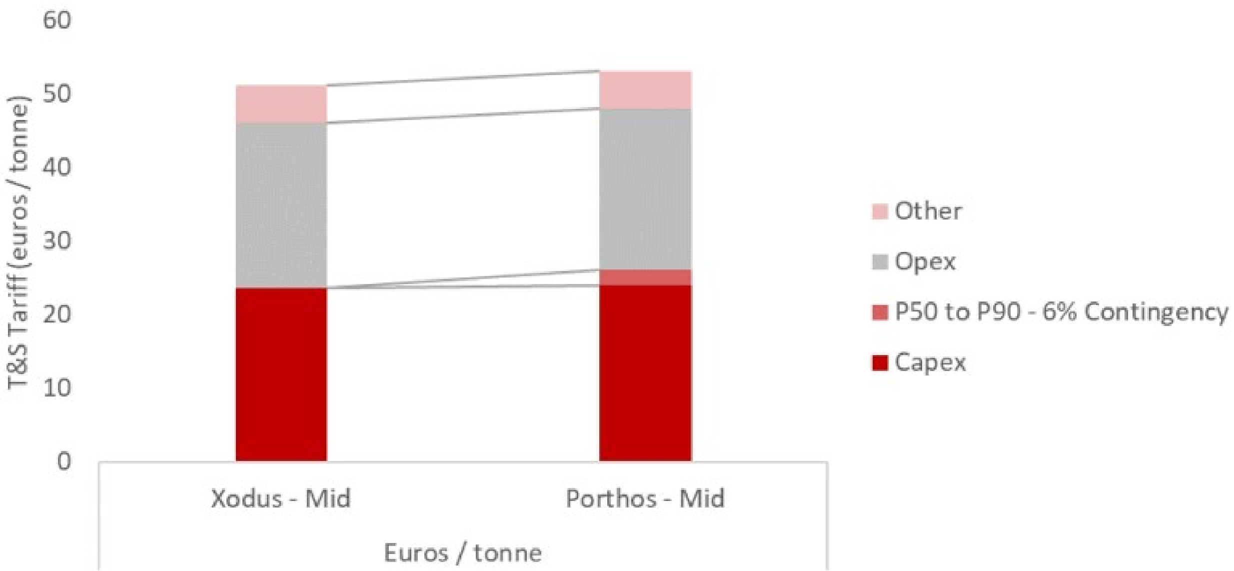

Figure 7.6 – Porthos project tariff estimate, 1.75MTPA utilization (Dutch Goverment, 2020)

The project T&S tariff was estimated at €53/t within a publicly disclosed tariff review in 2020 produced by Xodus (Dutch Goverment, 2020). The review considered Capex, Opex and financing costs to generate the T&S tariff, based on project specific data. Of the total tariff, around 70% are transportation costs, with a nearly even split between Capex and Opex. System utilization for this tariff calculation was noted as 70% of capacity or 1.75MTPA.

Aramis

The Aramis project, an onshore gathering pipeline emitter network and ship liquid transport and offshore pipeline to store, will utilize the onshore pipeline and compressor station of Porthos CCS and include additional receiving facilities for liquid CO_2 delivered by inland barges (Aramis, 2023). A new 200km offshore pipeline will be built to access a range of depleted hydrocarbon fields. The project is expected to have an initial capacity of 5MTPA and a maximum of 22MTPA based on the offshore pipeline capacity.

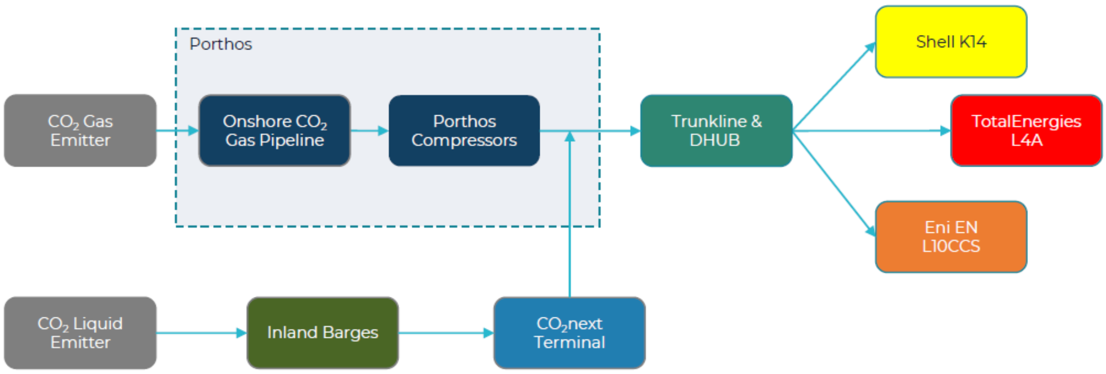

Figure 7.7 – Aramis project block diagram (Dutch Government, 2024)

According to a publicly available tariff review in 2024 (conducted by Xodus), the tariffs based on 7.5 MTPA utilization of the 21MTPA capacity trunkline are €91/t and €113/t for the gas and liquid routes respectively (Aramis Tariff Review , 2024). The individual system blocks are at different levels of maturity from Concept to FEED and the cost estimates will continue to evolve up to FID. A cost breakdown of the T&S elements was not provided separately.

7.2.4 Norway

Norway is a leader in CCS projects, with a strong focus on reducing CO_2 emissions through large scale projects and supportive policies. The country launched the world's first offshore CCS project, Sleipner, in 1996, followed by the Snøhvit project in 2008. These projects have collectively stored over 22 million tonnes of CO_2, demonstrating the viability of CCS technology. The government supports CCS through various policies, research activities and financial incentives.

Northern Lights

The Northern Lights project is the T&S element of the Norwegian Longship CCS demonstration project, with capture of CO_2 from industrial sources, shipping of liquid CO_2 from capture sites to an onshore terminal and pipeline transport from onshore to an offshore storage complex in the North Sea. Phase 1 is to provide 1.5MTPA capacity by 2025, with scope for an expansion in Phase 2 to 5MTPA by accepting CO_2 imports from other sources, including those outside of Norway and by fully utilizing the capacity of the offshore pipeline.

The project has published a FEED report describing the analysis completed on the project, including key engineering choices (Equinor , 2020). A cost estimate was completed during the FEED. However, the detailed costing information has been redacted and is not publicly available. An additional report completed on behalf of the Ministry of Energy and the Ministry of Finance by Atkins Norway and Oslo Economics, included a quality assurance review of the full-scale CO_2 management (published in Norwegian) (Norwegian Government, 2020). This report provides details combining capture and storage costs and discusses system utilization in detail. Tariff costs for the T&S elements which are only briefly mentioned in the 2020 review, are reported to be between €35-55/t. A separate document published by Gassnova (Gassnova, 2020) indicates that tariff costs of €55/t are to be expected, if 0.8MTPA is stored each year.

SINTEF CO_2LOS Projects

SINTEF has been engaged in a long-term project aimed at developing tools for cost estimation of CO_2 transport logistics, including both shipping and pipeline components. Currently in its fourth phase, the CO_2LOS project has generated a suite of software tools that enable project partners to estimate, screen, and evaluate the costs associated with various transport solutions for T&S networks. Although these software tools are not publicly accessible, a description of their functionality is available. Of particular relevance to this report is the Cost Estimation tool produced during the third phase of the CO_2LOS project. This tool is a parametric cost calculation model designed for comparative analysis of CO_2 transport logistics involving shipping and pipeline CCS scenarios. The software allows users to design diverse logistics solutions and estimate the associated capex and annual Opex. Furthermore, it facilitates the calculation of multi-stage logistics chains that integrate both pipeline and shipping transport methods. The software has been developed by Brevik Engineering AS and SINTEF.

The most recent report notes that the tool has the following limitations:

- Land cost, electricity cost, crew cost, and construction cost are not linked to the selection of geographical areas or locations. Instead, an average of available cost data is used in the calculations, though these costs have editable default values.
- The cost of process plant equipment from ASPEN is based on 2020 data, with no escalation included for subsequent years.
- The minimum number of ships can be changed in the Ship Transport calculation module. The software will always calculate using the fewest number of ships necessary to fulfil the logistics scenario and the minimum number specified.
- A limited number of inland locations connected to the sea by waterways are selectable within the tool. Users must ensure they select the appropriate sea destination. If the final destination requires an open sea voyage, it should be handled as a separate step since the program calculates the cost of an inland vessel for the segment on the inland waterway.

This tool has been developed to address the need for comparative analysis for project archetypes in Norway. It is similar to tools being used or developed in other countries, demonstrating the necessity of this type of tool in the emerging CCS industry.

7.3 North America

There are several CCS projects in both Canada and the USA which have been operating for more than 10 years, with some operating for decades. Operational projects have predominantly been used to facilitate enhanced oil recovery (EOR). However, the majority of new projects currently in the advanced development stage include storage without EOR, in either depleted hydrocarbon fields or saline formations.

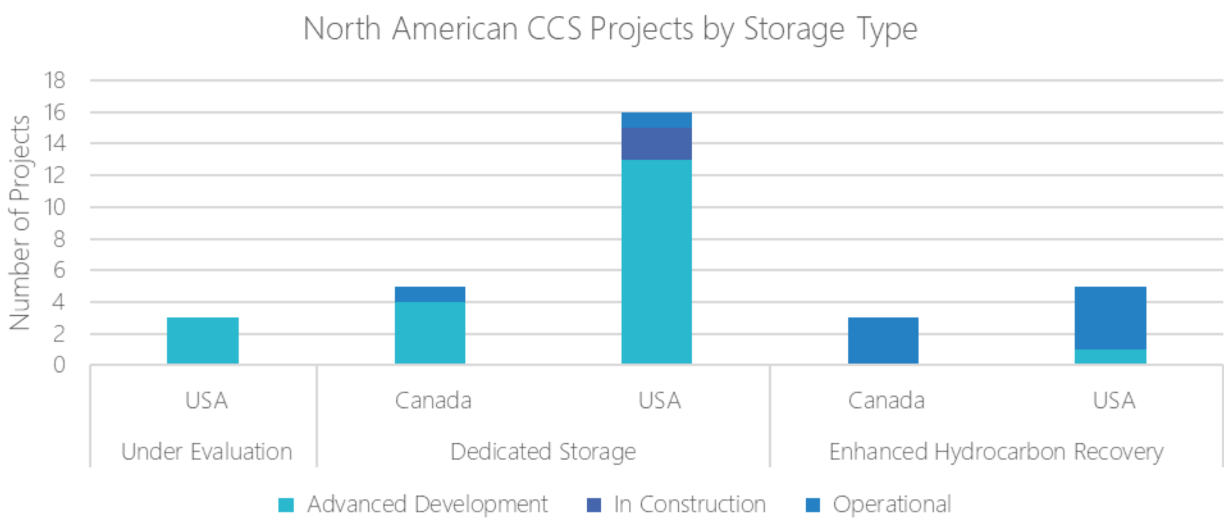

Figure 7.8 - North American CCS projects within report scope, by storage types

7.3.1 USA

As of December 2023, fifteen CCS facilities are currently operating in the United States, with a total capacity equal to capture 0.4% of the nation's total annual CO_2 emissions (Congressional Budget Office, 2023). An additional 121 CCS facilities are at various stages of development. Some of the projects included in the Congressional Budget Office review meet the screening criteria for this report and are included in the totals in Figure 7.8 but others do not, which helps to explain the difference in reported projects. Presently within the US, CCS is used in sectors that have the lowest costs for capturing CO_2 – including natural gas processing, ammonia, and ethanol production (Congressional Budget Office, 2023). Historically Enhanced Oil Recovery (EOR), injecting CO_2 into partially depleted oil reserves to recover more oil, has been widespread in the US due to the economic benefits from increased oil production. The US currently has approximately 8,400 km of onshore pipelines that carry CO_2 towards facilities which are typically located near major trunklines and storage sites.

The US has invested significantly within the CCS space through a range of funding programs. Annual appropriations for CCS research totalled US$5.3 billion between 2011 and 2023 (Congressional Budget Office, 2023). The American Recovery and Reinvestment Act of 2009 provided US$3.4 billion in funding and the 2021 Infrastructure Investment and Jobs Act will provide US$8.2 billion in advanced appropriations between 2022 to 2026. Importantly, companies in the CCS space are eligible for the 45Q federal tax credit, if the captured CO_2 annually meets the threshold level (Congressional Budget Office, 2023).

Several institutions within the US have published data relating to the cost of CO_2 T&S. A paper published in the international Journal of Greenhouse Gas Control has reviewed published costs of onshore transportation and storage, with the finding that costs can vary from US$4 - 45/t (Smith et al, 2021). Their paper states that the cost range depends on key issues such as distance, scale, reservoir geology, monitoring assumptions, and pipeline Capex.

The National Energy Technology Laboratory has published cost models for the transportation and storage of CO_2. These include a transport costing model for onshore pipelines (National Energy Technology Labratory, 2023) and a CO_2 capture, transport, and storage cost screening tool (National Energy Technology Labratory, 2024).

There are a mix of projects being undertaken in the USA, with both hub and single emitter sources being investigated. The table below generated by the Congressional Budget Office lists the current operating projects as of December 2023.

NAME OF FACILITY	DATE CCS OPS	LOCATION	TYPE OF PRODUCTION	EOR PROJECT	CAPTURE CAPACITY (MTPA)
Terrell	1972	Texas	Natural Gas Processing	Yes	0.5
Enid Fertilizer	1982	Oklahoma	Ammonia (Fertilizer)	Yes	0.2
Shute Creek	1986	Wyoming	Natural Gas Processing	Yes	7.0
Great Plains	2000	North Dakota	Hydrogen and Ammonia	Yes	3.0
Core Energy	2003	Michigan	Natural Gas Processing	Yes	0.4
Arkalon	2009	Kansas	Ethanol	Yes	0.5
Century Plant	2010	Texas	Natural Gas Processing	Yes	5.0
Bonanza BioEnergy	2012	Kansas	Ethanol	Yes	0.1
Air Products	2013	Texas	Hydrogen	Yes	0.9
Coffeyville	2013	Kansas	Hydrogen and Ammonia	Yes	0.9
Lost Cabin	2013	Wyoming	Natural Gas Processing	Yes	0.9
PCS Nitrogen	2013	Louisiana	Ammonia (Fertilizer)	Yes	0.3
Petra Nova	2017	Texas	Electric Power	Yes	1.4
Illinois Industrial	2017	Illinois	Ethanol	No	1.0
Red Trail Energy	2022	North Dakota	Ethanol	No	0.2

Table 7.2 - USA CCS project listing (Congressional Budget Office, 2023)

This project list has been reviewed in conjunction with the GCCSI data to identify if recent and high-capacity projects have published cost data. The paragraphs below discuss these projects.

Shute Creek

The Shute Creek CCS facility, a single emitter with pipeline to local store, is one of the longest running CCS facilities in the world, beginning operations in 1986. The CCS facility (run by ExxonMobil) captures CO_2 from natural gas processing, before transporting and selling to nearby fields for EOR. The transportation infrastructure is a large cost component, as the pipeline infrastructure is circa 460km in length. In 2022, ExxonMobil made a final investment decision to expand the carbon capture and storage, capturing an additional 1.2MTPA, on top of the 6 - 7MTPA installed capacity (ExxonMobil, 2022). This expansion is at a predicted cost of US$400 million (ExxonMobil, 2022).

No detailed information on project costs has been made publicly available.

Great Plains

The Great Plains Synfuels Plant, a single emitter with pipeline to store, is a significant CCS project operated by the Dakota Gasification Company. The facility captures CO_2 from the gasification of lignite coal to produce synthetic natural gas (SNG). Captured CO_2 is transported via a 328km pipeline to the Weyburn and Midale oil fields in Saskatchewan, Canada, for EOR. A proposed CCS extension in the facility will enable the capture of up to an additional 3.5MPTA of CO_2 per year, as announced in 2021 (Basin Electric Power Cooperative, 2021). This extension will make Great Plains the first CCUS project in the U.S. to use both EOR and geologic storage.

No information on project costs has been made publicly available.

Century Plant

The Century Plant CCS facility, a single emitter with pipeline to local store located in Texas, is one of the largest CCS projects in the world. Owned by Occidental Petroleum, the facility captures CO_2 from natural gas processing and uses it for EOR in the Permian Basin. The initial construction cost of the project was reportedly approximately $1.1 billion (Besta, 2019).

This was a commercial enterprise and no further information on project costs has been made publicly available.

Petra Nova

The Petra Nova CCS project, located near Houston, captures around 90% of the CO_2 from 30% of flue gas emissions from a single boiler unit in the coal-fired power station and transports it via pipeline to a storage site. The captured CO_2 is transported via a 130km pipeline to the sandstone Frio Formation of the West Ranch oil field, where it is used for EOR (Office of Fossil Energy and Carbon Management, 2017) (U.S. Energy Information Administration, 2017). The project started operations in 2017 but was temporarily shut down in May 2020 due to low oil prices impacting the economics. The project was restarted in September 2023. No information on project costs has been made publicly available from the developer. Research papers have made estimates on the lifecycle costs, but it is unclear how accurate these costs are.

Air Products and Chemical Louisiana Clean Energy Complex

Air Products and Chemicals Inc has reached a final investment decision for a low-carbon hydrogen production and low-carbon ammonia production complex in Ascension Parish, Louisiana. As part of the project, CO_2 will be captured, transported, and stored in saline aquifers. CO_2 will be transported by pipeline to multiple inland sequestration sites located along a pipeline corridor, extending up to 35 miles to the East of the new production facility (Louisana Clean Energy, n.d.). The facility is in construction, with plans to be operational in 2027.

No information on project costs has been made publicly available.

CapturePoint Solutions Central Louisiana Regional Carbon Storage Hub

CapturePoint Solutions have reached a final investment decision to build the Central Louisiana Regional Carbon Storage (CENLA) Hub in Louisiana, an onshore gathering pipeline network to store (CapturePoint, 2023). The first phase of the CENLA Hub project will involve the capture of dedicated CO_2 emissions from natural gas processing facilities owned by affiliates of Energy Transfer located in North and Central Louisiana, as well as from other industrial sources in the area. These emissions will be transported by pipeline for deep underground sequestration in the CENLA Hub. CapturePoint's future plans include expansions to capture, transport and store emissions at the CENLA Hub from other sources in the industrial corridors of Southern Louisiana.

No information on project costs has been made publicly available.

7.3.2 Canada

The CCS landscape within Canada, specifically in the provinces of Alberta and Saskatchewan, is advanced in its development. Two T&S projects, Quest and the Alberta Carbon Trunk Line, have been operational since 2015 and 2020 respectively in Alberta. In Saskatchewan, the Boundary Dam project is operational and previous successful pilot scale projects, Weyburn Midale and Acquisitor, continue to contribute valuable research. The government continues to prioritise CCS, with a total of 25 new CCS projects selected in 2022 for future evaluation by the Alberta government.

Alberta has invested more than CAD$1.2 billion into two successful CCS projects and these projects are required to annually report technical information and lessons learned to the Government of Alberta. Alberta's CCS Knowledge Sharing Program include a disclaimer and full terms and conditions of use (Alberta Government, 2024), with the intention to make CCUS technologies more accessible.

Quest Project, Canada

The Quest CCS facility, a single emitter with pipeline to store, is located at the Scotford Upgrader facility near Edmonton, Alberta. Construction on the facility began in September 2012, with CCS operations starting in November 2016 (Alberta Department of Energy, 2023). The project captures, transports and stores CO_2 from Shell's Scotford Upgrader, a production plant for synthetic crude oil, with an original capacity of up to 1.2 MTPA. During this process, the upgrader capture facility dehydrates and compresses the CO_2 for transportation. The T&S system includes a 60km underground pipeline to the storage site, where CO_2 is injected through three previously drilled injection wells, 2km beneath the ground. This storage facility is within a saline formation near Thorhild, Alberta, and designed for permanent storage. As of December 2022, Quest has surpassed 7.7 million tonnes of injected CO_2 since project start-up.

As of 2022, reservoir performance and injectivity assessments have indicated that the project will be capable of sustaining adequate injectivity for the duration of the project life, therefore no further well development is expected to be required (Alberta Department of Energy, 2023).

The project provides detailed, high-quality cost data for design, construction, and operations phases, published over several years as part of Alberta Government's CCS knowledge sharing initiative (Alberta Department of Energy, 2023). Key data from the review is discussed in the summary section below.

ACTIVITY	AREA	COST TYPE	ACCURACY	TOTAL PROJECT REPORTED COSTS (CAD$ MILLION)
Transport	Activities – Design, Construction & Commissioning	Capex	Out-turn cost (Assumed)	43.1
	Transportation Facility Components & Procurement	Capex	Out-turn cost (Assumed)	27.9
	Operating Costs	Opex	Out-turn cost (Assumed)	1.9
Storage	Activities – Design, Construction & Commissioning	Capex	Out-turn cost (Assumed)	109.3
	Injection Facility Components & Construction	Capex	Out-turn cost (Assumed)	6.6
	Operating Costs	Opex	Out-turn cost (Assumed)	20.3

Table 7.3 – Quest 2022 operating cost (Alberta Department of Energy, 2023)

As part of the reporting requirement, the Quest facility also publishes a levelized cost per tonne for the T&S elements each year. The cost does not appear to include financing cost/profit/tax etc. and is not thought to be equivalent to a tariff that a user would pay. The levelized cost per tonne for the 2022 update is noted below.

ACTIVITY	CAPEX / OPEX	COST TYPE	ACCURACY	PROJECT LIFE	ESTIMATED MASS OF CO_2 CAPTURED (MTPA)	LEVELIZED COST PER TONNE (CAD$/TONNE)
Transport	Capex	Life of Project cost	Out-turn	25 years	1.08 MTPA	10.05
	Opex	Life of Project cost	Out-turn	25 years	1.08 MTPA	0.17
Storage	Capex	Life of Project cost	Out-turn	25 years	1.08 MTPA	8.30
	Opex	Life of Project cost	Out-turn	25 years	1.08 MTPA	8.76
T&S Total	Capex and Opex			25 years		27.28

Table 7.4 - Quest levelized cost per tonne (Alberta Department of Energy, 2023)

Alberta Carbon Trunk Line Project

The Alberta Carbon Trunkline (ACTL) Project, an onshore gathering pipeline network to store, is a 240km pipeline that carries captured CO_2 from two industrial facilities in Alberta, Canada. The ACTL has a design capacity of up to 14.6 million tonnes of CO_2 per year, injecting CO_2 into depleted oil reservoirs. Commercial operations began in 2020, with the pipeline owned and operated by Wolf Midstream and the storage site owned by Enhance Energy. The system follows an open access concept with 3rd party emitters, currently North West Rewater Partnership, Sturgeon Refinery and Nutrien's Redwater Fertilizer Facility, using the system to transport and store emissions (Enhance Energy Inc., Wolf Carbon Solutions Inc, North West Redwater Partnership, 2023).

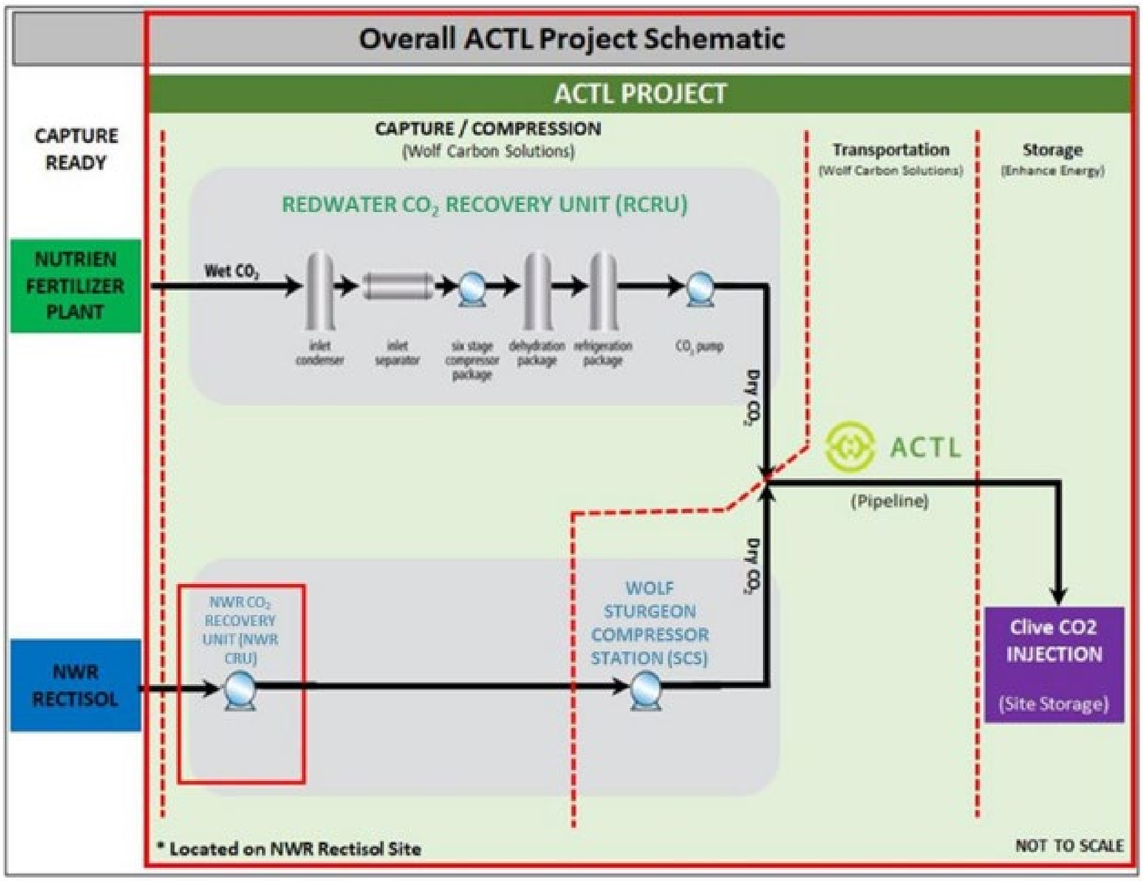

Figure 7.9 - Overall ACTL project schematic (2022) (Enhance Energy Inc., Wolf Carbon Solutions Inc, North West Redwater Partnership, 2023)

CO_2 is delivered to the T&S system by emitters at varying pressures where it is then transported to the storage site via an onshore 240km pipeline. The CO_2 is used by the onshore Clive EOR and Storage project and injected at a depth of 1900m below ground. CO_2 recovered from the produced oil is recycled and reinjected at the Clive site. (Enhance Energy Inc., Wolf Carbon Solutions Inc, North West Redwater Partnership, 2023). The ACTL project has released high-quality lifecycle costing data for transportation and storage from construction to commercial operations, through the Alberta Government CCS knowledge sharing initiative. The following data summarizes the 2022 levelized costs and total project costs reported from 2009 to 2022.

ACTIVITY	AREA	COST TYPE	ACCURACY	TOTAL PROJECT REPORTED COSTS (CAD$ MILLION)
Transport	Activities – Design, Construction & Commissioning	Capex	Out-turn cost (Assumed)	326.4
	Operating Costs (SCS and ACTL)	Opex	Out-turn cost (Assumed)	27.9
Storage	Activities – Design, Construction & Commissioning	Capex	Out-turn cost (Assumed)	57.4
	Operating Costs	Opex	Out-turn cost (Assumed)	24.7

Table 7.5 - Alberta Trunkline 2022 Capex and Opex (Enhance Energy Inc., Wolf Carbon Solutions Inc, North West Redwater Partnership, 2023)

As part of the reporting requirement, the ACTL team also publishes a levelized cost per tonne for the T&S elements each year. The cost does not appear to include financing cost/profit/tax etc and is not thought to be equivalent to a tariff that a user would pay. The levelized cost per tonne for the 2022 updates is noted below.

ACTIVITY	CAPEX / OPEX	COST TYPE	ACCURACY	PROJECT LIFE	ESTIMATED MASS OF CO_2 CAPTURED (MTPA)	LEVELIZED COST PER TONNE (CAD$/TONNE)
Transport	Capex	Life of Project cost	Out-turn	25 years	1.62 MTPA	15.88
	Opex	Life of Project cost	Out-turn	25 years	1.62 MTPA	13.82
Storage	Capex	Life of Project cost	Out-turn	25 years	1.62 MTPA	3.39
	Opex	Life of Project cost	Out-turn	25 years	1.62 MTPA	10.84
T&S Total	Capex and Opex		Out-turn	25 years		43.93

Table 7.6 - Alberta Trunkline levelized cost per tonne (Enhance Energy Inc., Wolf Carbon Solutions Inc, North West Redwater Partnership, 2023)

7.4 Asia and Australia

While there are a wide range of projects planned for the APAC region, few facilities have reached the operational phase. There remains widespread interest with many countries in Southeast Asia looking to utilize their depleted oil and gas reservoirs for the sequestration of CO_2. Despite multiple projects being within the advanced development, in construction and operational phases (Figure 7.10), there is limited published information on forecasted and realised costs, within the APAC region.

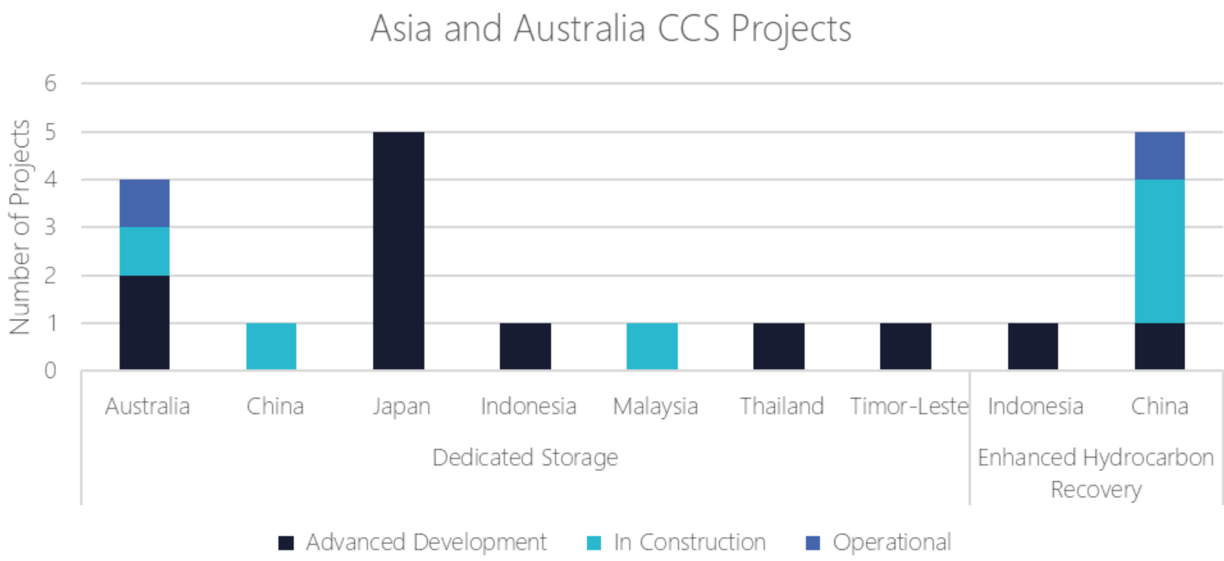

Figure 7.10 - CCS Projects within Asia and Australia

The following sections discuss the literature found for projects in the Asia and Australian region.

7.4.1 Australia

There are 4 main projects highlighted in the GCCSI Global Status of CCS Report that meet the screening criteria as stated in section 7.

- One in Operation – Gorgon Carbon Dioxide Injection Projects
- One in Construction – Moomba Carbon Capture and Storage Project
- Two in Advanced Development – Victorian Government CarbonNet & Pilot Energy Cliff Head.

Gorgon Carbon Dioxide Injection Project

The Gorgon facility, a single emitter with pipeline to local store, predominantly produces LNG through its liquefaction process. However, as part of the gas treatment prior to liquefaction, CO_2 is separated from the natural gas and injected into a saline aquifer. The facility is managed by the Chevron-led Gorgon Joint Venture (GJV) and originally planned to inject 3.3 - 4 MTPA of CO_2 into the Dupuy Formation, a geological layer more than 2km beneath Barrow Island (Government of Western Australia: Department of Energy, Mines, Industry Regualation and Safety, n.d.).

The GJV started injecting CO_2 in early August 2019, but operational injection rates have generally been lower than originally planned. Table 7.7 - Gorgon CO_2 injection rates (Chevron, 2023) (Chevron , 2022) (Chevron, 2021) (Chevron, 2020) summarises the CO_2 removal rates from the feed gas, and the volume injected for storage. Limitations were placed on the injection rate in December 2020 by the WA Department of Mines Industry Regulation and Safety, limiting the injection rate until such a time that the pressure management systems were fully operational (Chevron, 2021).

	CAPTURED CO_2		INJECTED CO_2	
	(Sm^3 CO_2)	MTPA	(Sm^3 CO_2)	MTPA
2023	2.56E+09	5.07	8.62E+08	1.71
2022	2.57E+09	5.09	8.25E+08	1.63
2021	1.62E+09	3.21	1.10E+09	2.18
2020	1.48E+09	2.93	8.51E+08	1.68

Table 7.7 - Gorgon CO_2 injection rates (Chevron, 2023) (Chevron , 2022) (Chevron, 2021) (Chevron, 2020)

Injection of CO_2 into the reservoir has required continuous optimization to ensure reliable performance and to maximize injection rates. There have been a number of technical challenges that the GJV has had to overcome over time. Managing these challenges will be common to all CCS projects and can impact performance and add additional costs.

The Gorgon project was awarded funding from the Australian Commonwealth Government Low Emission Technology Development Fund in 2008. As part of the funding reporting requirements the actual eligible expenditure on the project from 2009 to 2021 was reported. The actual and eligible expenditure on the Gorgon project publicly reported in the end of project report contains a mix of Capex and Opex costs for the period. The costs reported are useful and the expenditure on key elements of the system are segregated. However the costs are not profiled, and it is difficult to understand when the expenditure occurred (Chevron, 2021).

Moomba Carbon Capture and Storage Project

The project, a single emitter with pipeline to local store, proposes to capture 1.7MTPA of CO_2 that is currently separated in the acid gas removal process at the Moomba gas processing plant in South Australia. The captured CO_2 will be reinjected into depleted hydrocarbon reservoirs at Cooper Basin. The project is expected to be operational during 2024.

A high-level project cost has been provided for the Moomba Carbon Capture and Storage project, which is estimated at US$220 million (Santos, 2024). No details have been provided on the breakdown of costs between capture, transport, and storage.

CarbonNet Project

The CarbonNet Project, a pipeline gathering network to store, is currently being investigated by the Victorian Government. CarbonNet plans to build a 100km CO_2 pipeline from the Latrobe Valley to the Gippsland Basin for storage (Victoria State Government, 2023). This approach would enable multiple emitters to be collected and stored in a single site. High level cost analysis has been completed for the whole development including construction of manufacturing plants, capture plants, transport, and storage systems. The costs reported are combined therefore a detailed cost estimate breakdown for the T&S system has not been publicly disclosed.

Given the report looks to highlight the economic opportunities for the region rather than provide detailed costing estimates of the project, it is suspected that the costs included are pre-appraise level estimates.

Pilot Energy Cliff Head Project

The Pilot Energy Cliff Head project involves multiple disparate emitters with dedicated ship/rail/road liquid transport, to a common onshore hub and pipeline to store. The project plans to convert the existing Cliff Head oil field onshore/offshore facilities to provide a carbon management service to third parties. The project would require ship transport to the facility for storage, with the industrial zone at Kwinana, Victoria targeted as a potential emitter site for collection. The conversion of the existing facility is currently in the FEED stage of engineering design, with no costings provided. A target of AU$20/tonne for the levelized cost of storage (Pilot Energy, 2023) has been announced with some information on the project included in the publication, however the breakdown of costs to generate this figure was not disclosed.

7.4.2 China

There are multiple projects planned and in operation in China, collecting emissions from a range of sources (Yang, 2023). Predominantly, the projects in China plan to inject CO_2 into producing hydrocarbon reservoirs for EOR.

It is noted that there are likely to be several publications and extensive research effort in this region. However, as noted in the methodology section of the report, this study has only reviewed documentation published in English, which is a genuine barrier when considering China in particular. No detailed Capex, Opex or life of project costing data, has been identified in documents published in the English language, for China's CCS projects.

From publicly available sources, the following two CCS projects have been identified as high-profile projects to be undertaken in China.

Sinopec Shengli Power Plant

The Shengli Power Plant project is a single emitter with pipeline to store project. Sinopec plan to build a post-combustion capture system to a newly built thermal power production unit as part of Phase III of the Shengli Power Plant development in Dongying City Shandong Province. The CO_2 capture facilities with a capacity of 1MTPA are expected to begin operation in the 2020s. The captured CO_2 would be transported by pipeline to the Shengli oilfield for EOR. No information on project costs has been made publicly available.

Sinopec Qilu-Shengli

Sinopec Qilu-Shengli CCS project is a single emitter with a pipeline to local store. The project is currently operational, taking CO_2 captured from the gasification of coal. The CO_2 stream is transported in gas phase 75km to the Chunliang / Zhenglizhuang production units of the Shengli oil field. The gaseous CO_2 is then liquefied and pumped to the well sites for use in for EOR (Sinopec, 2023). No information on project costs has been made publicly available.

7.4.3 Japan

The Japan Organisation for Metals and Energy Security (JOGMEC) works closely with the Japanese government and has been supporting Advanced CCUS projects from 2023 (JOGMEC, 2024). Initially, seven projects were selected to conduct feasibility studies to examine the possibility of building a CCS value chain, from capture to storage.

During 2024, JOGMEC continued to support the basic engineering design for the entire CCS value chain and assessment of CO_2 storage potential with the aim of reducing uncertainties related to CCS costs and underground storage. This analysis will be completed for an expanded 9 projects. The government has set a target of 6 - 12 MTPA of CO_2 storage by 2030. To achieve this, JOGMEC anticipates final investment decisions to be reached during 2026.

The projects being supported within Japan are associated with a combination of local and international storage sites. There are several areas where emissions sources are local to potential storage sites (Tomakami Area CCS, Metropolitan Area CCS and Higashi-Niigata Area CCS). In this scenario, the plan is to utilize pipelines for transportation of the CO_2 from emitters to storage sites.

Transport costs are crucial in many Japanese CCS projects due to the relative locations of the emitters and stores. For instance, Offshore Western Kyushu CCS will target emissions from Western Japan, using pipelines and ships for transportation. Similarly, the Tohoku Region West Coast CCS project plans to target emissions across Japan, also utilizing pipelines and ships for transport.

Investment is also occurring in multi-country CCS projects. There are 4 projects that have been identified to transport CO_2 to other storage sites outside of Japan, in Malaysia and Australia. These projects will be dependent on pipelines to collect CO_2 from emitters and deliver to a hub for transport via ship to the storage sites. From this review, it is evident that Japan plans to cooperate with the wider Asia Pacific region to store emissions. Japanese companies are planning investments in projects in Southeast Asia in Thailand, Malaysia, and Indonesia.

A number of projects are currently entering the basic engineering stage, at which point project specific cost estimates will be developed and matured. Data compiled by Mizuho Bank (Mizuho Group, 2023), which appears to cover “pre-appraise level” estimates, was the only data found in this region, but it is noted that there is likely to be other data published in local language. For completeness, the costs found are shown in Table 7.8.

	DISTANCE FROM EMITTER TO STORE	UNIT COST (US$/ TONNE OF CO_2 TRANSPORTED)
Pipeline	20km	18
LCO_2 Carrier	1,100km	64
Onshore Storage	Not Disclosed	43
Offshore Storage	Not Disclosed	48

Table 7.8 - Generic cost factors compiled by research department Mizuho Bank (Mizuho Group, 2023)

7.4.4 Indonesia

Indonesia's Minster of Energy and Mineral Resources has issued a regulatory framework for CCS and CCUS operations, providing clarity on various crucial aspects of CCS implementation, licensing requirements, CCS project lifecycle and potential business schemes (Simmons, 2024). As of December 2023, there were 15 CCS/CCUS projects in Indonesia undergoing evaluation or at the preparation stage, with a total projected investment value of US$1.1 billion and potential storage value of 4.3 gigatonnes of CO_2 (Simmons, 2024). A range of storage assessment studies have concluded that Indonesia has a potential storage capacity of 12.2 billion tonnes (ACN, 2023).

No detailed Capex, Opex or life of project costing data, has been found for Indonesia's CCUS projects following a review of the projects listed by GCCSI and Asia CCS network publications.

Tangguh CO_2 EGR, BP Tangguh

The Tangguh CO_2 project is a single emitter with pipeline to local offshore store. BP and the Tangguh LNG Joint Venture Partners (Mitsubishi, Inpex, CNOOC, JX Nippon, KG Mitsui and LNG Japan) have been involved in the production and delivery of integrated CCS projects at Tangguh. The Tangguh LNG ERG / CCS project will have three injection wells, one offshore injection platform, one offshore CO_2 pipeline and onshore facilities for CO_2 removal, processing, and compression (BP, Tangguh Enhanced gas recovery/carbon capture, utilization and storage, 2024).

Tangguh is the largest gas producer in Indonesia, accounting for approximately 20% of the country's natural gas production (BP, bp signs MoU to evaluate CO_2 storage in Tangguh, 2023). The Tangguh CCS project is the most advanced CCS project in Indonesia, with the development plan receiving approval from the Government of Indonesia in 2021 and the project partners taking the final investment decision to proceed in 2024.

No detailed Capex, Opex, or life of project costing data has been made available for the Tangguh CCS Project.

7.4.5 Malaysia

Kasawari CCS Phase II

The Kasawari CO_2 Sequestration (CCS) project, a single emitter with pipeline to local shore located in offshore Sarawak, is currently in construction. It reached FID in 2022 and plans to start injecting CO_2 by the end of 2025 (Petronas, 2022). The project will remove CO_2 from a single facility, the Kasawari Phase one development, and expects to store 3.3MTPA of CO_2 from flaring/venting emissions.

The project is located in Block SK316, approximately 200km off Bintulu in Sarawak. This location additionally includes the NC3 gas field, which will supply feedstock gas to the Petronas LNG complex in Bintulu. The Kasawari CCS project will include the construction and installation of a fixed offshore CCS platform. Compressed CO_2 will be reinjected into the depleted reservoir via a 138km, 16-inch subsea pipeline, with approximately 71 to 76 MT of CO_2 expecting to be reinjected into the M1 field over the project life (NS-Energy, 2023).

No detailed Capex, Opex, or life of project costing data has been made available for the Kasawari CCS Project.

7.4.6 Singapore

To meet the 2030 Nationally Determined Contributions (NDC), Singapore has decided to adopt a suite of decarbonisation measures, investing in CCS. The Government is partnering with companies and countries to further explore cross-border CCS projects, with the wider aim of turning the region into a CCS hub.

S-Hub Consortium, Singapore

ExxonMobil and Shell have formed an S-Hub consortium to evaluate and develop a cross border CCS project, reducing emissions in Singapore. S-Hub and the Singapore Economic Development Board (EBD) signed a Memorandum of Understanding (MoU) in December 2023, to coordinate the planning and development of a CCS project. The project aims to capture and permanently store at least 2.5MTPA of CO_2 by 2030 (S-Hub Consortium, 2024).

At this point in time, no detailed Capex, Opex, or life of project costing data has been made available for any of the planned S-Hub Consortium projects.

Transportation of Liquified CO_2, Singapore

A Joint Study Agreement (JSA) was signed in 2022 between Chevron New Energies International Pte. Ltd and Mitsui O.S.K Lines Ltd, on the feasibility of transporting liquified carbon dioxide from Singapore to permanent storage locations offshore Australia. This study will allow the parties to explore the technical and commercial feasibility of initially transporting up to 2.5MTPA of liquified CO_2 by 2030 (Chevron, 2022).

This JSA complements a separate consortium between Air Liquide, Chevon, Keppel Infrastructure, and PetroChina to explore the development of large-scale carbon capture, utilization, and sequestration solutions within Singapore (Chevron, 2022). The consortium, who have signed a MoU, intends to research, test, and develop technological, logistical, and operational solutions for CCS in Singapore, primarily to support the energy and chemicals sector. At this stage, no further information has been published on specific projects and solutions since the commencement of the MoU.

7.4.7 Timor-Leste

Bayu-Undan CCS Project, Timor-Leste

Santos, the operator of the Bayu-Undan offshore gas production facility in Timor-Leste, has announced entry into the FEED phase for a proposed CCS project. The site is predicted to store up to 10MTPA of CO_2 safely and permanently (Santos, 2022). The FEED work will include engineering and design for additional CO_2 processing capacity at the Darwin LNG plant in Australia, plus the repurposing of the Bayu-Undan facilities for carbon sequestration operations, after gas operations cease.

Since 2022, no further detailed Opex, Capex, or life of project costing information has been published.

7.5 Case Study Findings

Reviewing the available literature has been an involved and complex task. This study has reviewed many different projects around the world which highlights the difficulties stakeholders may have in evaluating the costs of building and running T&S systems. It confirms the initial reason for this study; while costs are published worldwide, there are few new and useful data sources to inform policy or to help benchmark the performance of projects.

The review of data has highlighted the following key issues common to Capex, Opex, and life of system T&S costs:

1. Project specific factors such as emitter location and geography of the region result in varying system designs. The projects reviewed broadly follow common archetypes but ultimately the design and operation of the systems are all different.
2. Often, the estimate accuracy and other core assumptions such as contingency allowances, are not reported.
3. It is often challenging to identify details such as project archetype, pipeline length, compression provision, store type, and well counts from publications. This can result in difficulties in interpreting the reported costs.
4. It is often unclear if an allowance has been made for financing the project in the costs reported, which can play a major role in driving the cost that emitters would pay.
5. The system utilization profile is rarely stated in detail.
6. The 'cost base' of the costs are not often stated, and assumptions need to be made based on publication dates, which is an issue given the surge in inflation between 2021 and 2024, particularly in Europe.

To help highlight why these points are relevant for this discussion, summary data from mature projects or those in operation have been collated and produced in Table 7.9 - Summary of case study . The unit costs, which are ultimately a function of the Capex and Opex estimates and project financing, are published by either a government review/audit of the project or published as part of a government linked initiative, creating a level of confidence in the data for the purposes of this discussion. To allow a direct comparison between the unit costs reported, they have been converted in to £/t from their original currencies using an average 2024 exchange rate.

COUNTRY	PROJECT	SYSTEM ARCHETYPE	CAPEX COST ESTIMATE ACCURACY	SYSTEM CAPACITY	PROJECT LIFE	FINANCING COSTS	YEAR OF REPORTING	UNIT COSTS
UK	HyNet	Onshore and Offshore Pipelines Repurposed and New Build Depleted Offshore Gas Store	+/-30% Advanced Development (Pre-FID)	Up to 10MTPA	25	10% WACC	2022	Tariffs: £38.50/t – 1MtCO_2 £17.50/t – 5MtCO_2 £10.00/t – 10MTPA ((HyNet North West, 2020)
Netherlands	Porthos	Onshore and Offshore Pipeline, Depleted Offshore Gas Store	Not Stated Advanced Development (Pre-FID)	Up to 2.5 MTPA	15	Not Stated	2020	Tariffs : £31.93/t – 2.5 MTPA £44.73/t – 1.75 MTPA ((Dutch Goverment, 2020)
Netherlands	Aramis	Onshore and Offshore Pipeline New build, Liquid CO_2 Storage Terminal (Ship) Depleted Offshore Gas Store	+/- 25 to 35% Advanced Development (Pre-FID)	Up to 21 MTPA	15	Not Stated	2024	Tariffs: £76.67/t Pipeline - 7.5MTPA System Capacity £95.33/t Ship – 7.5MTPA System Capacity (Dutch Government, 2024)
Norway	Northern Lights	Liquid Shipped Gathering, Offshore Pipeline Offshore Aquifer Store	Not Stated Advanced Development (Pre-FID)	Up to 1.5 MTPA	Not Stated	Not Stated	2020	Tariff (assumed): £45.89/t (transported and stored) - 0.8 MTPA (Gassnova, 2020)
Canada	Quest	Onshore New Build Pipelines Onshore Aquifer Store	Operational	Up to 1.2 MTPA	25	Not Stated	2023	Life of Project T&S Cost: £15.29/t – 1.1 MTPA (Alberta Department of Energy, 2023)
Canada	Alberta Trunkline	Onshore Pipelines and Onshore store Depleted Oil Store	Operational	Up to 14.6 MTPA	25	Not Stated	2023	Life of Project T&S Cost: £22.22/t - 1.62 MTPA (Enhance Energy Inc., Wolf Carbon Solutions Inc, North West Redwater Partnership, 2023)

Table 7.9 - Summary of case study findings

It is important to note that the accuracy of the estimates in Table 7.9 varies, as the data is explicitly stated in some reports but not others. Both the project lifespan and the utilization of the installed capacity varies between projects. It is also unclear in some of the publications what financing and return assumptions have been used when generating tariff values, or if any allowance for financing costs have been included.

The range of costs vary from £15/t to more than £90/t (Table 7.9). This finding is a result of a range of factors including the archetype, location, year of construction, utilization, and financing costs. Understanding exactly what factors set the cost for a given project in each range is less clear and is a challenging task to undertake without extensive knowledge and access to the unit cost data.

The table indicates a scarcity of recent, reliable information sources. This supports the study's premise that cost information for these systems is valuable and costly to obtain, thus not freely available.

Xodus' expertise in developing cost estimates for CCS projects has identified key cost drivers in project design. The following sections will detail the Capex, Opex, and business case decisions impacting tariffs for these systems. Issues with estimating and reporting specific costs are discussed in the recommendations section.

8 TASK 3 - KEY COST DRIVERS INSIGHT AND DISCUSSION

8.1 Introduction

The following sections highlight the areas which drive project storage costs and/or tariffs in T&S systems. These conclusions have been identified from the learning of CCS and oil & gas projects, and from knowledge and experience of the review team.

The intent of the following section is to provide the reader with genuine insight into how system design, cost estimating process and operation of the system drives T&S costs/tariffs. Describing how the various elements contribute to driving the out-turn costs for storing CO_2 is thought to provide significantly more value to the reader than discussing the Capex or Opex of individual components in isolation as these costs are well known to vary depending on the project archetype, location etc.

8.2 Transport System Key Insights

8.2.1 Location of Emissions and Store

The location of emitters in relation to their associated stores clearly has a direct impact on the costs of building the T&S system. Longer distances between the emitters and stores will drive up the costs because of the need to construct or operate longer transportation routes (pipelines or ships). Historically, the location of large emitters, such as refinery and petrochemical complexes have been linked to the availability of hydrocarbons in each region and industrial areas can often be found at costal locations near offshore or onshore hydrocarbon fields. The same can be said of processes consuming bulk materials such as coal, oil and/or minerals such as coal for power stations and limestone for cement production.

The development of large-scale gas transmission networks in the latter part of the 20th century in developed countries has partially decoupled the requirement for large emitters to be located close to hydrocarbon basins and the location of potential future stores. The economies of scale created by the interconnected gas networks in Europe is a prime example of this effect with large scale emitters now dispersed across the continent drawing gas from a large, mature, and relatively low-cost method of transporting energy over large distances. Figure 8.1 plots all combustion plants with a thermal output of 50MW or more in Europe as evidence of this effect.

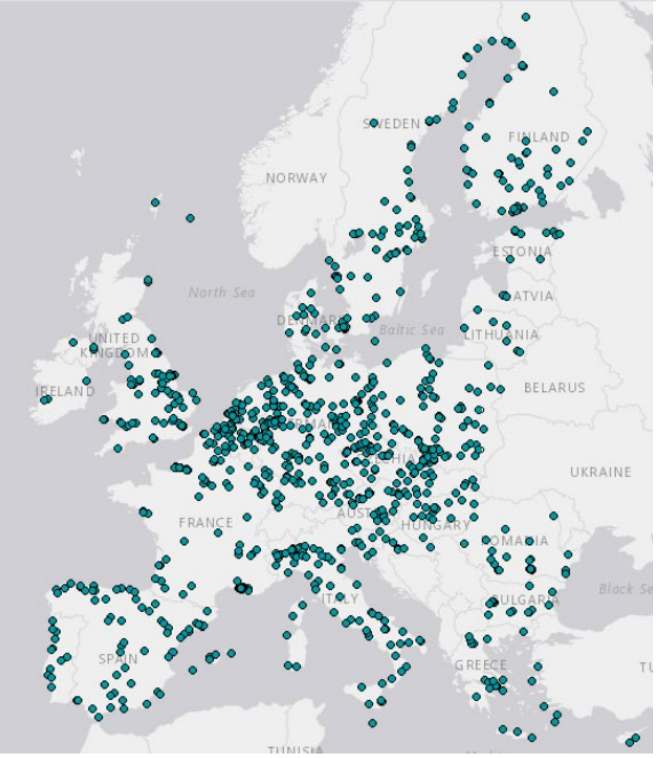

Figure 8.1 - Large Combustion Plant, 50MW or greater output, CO_2 Emission Locations in Europe (European Environmental Agency, 2020)

CO_2 T&S systems have relatively few building blocks and the Capex of the pipeline is known to play a significant role in the Life of Project T&S Cost. Like all linear asset types, similar to electricity transmissions systems, the installed length of a given pipeline size is proportional to the final installed cost with the requirement for intermediate compression also playing a significant role. For an equivalent volume of CO_2, transporting it by ship over longer distances necessitates either a greater number of ships or ships with larger capacities. Additionally, this requires bigger storage tanks and incurs higher operational costs due to increased fuel consumption. Irrespective of whether pipeline or shipped transport systems are used, the cost to store emissions located longer distances from storage locations will always play a significant role in driving higher costs for these emitters.

It is clearly important that the distance between emitter and store is considered in cost estimates and benchmarking data. While some published data does address this issue, other sources do not explicitly highlight the assumptions used to generate the estimates.

8.2.2 Project Life Span, Capacity Utilization and Life of T&S Project Costs

The Capex and system capacity of a CCS T&S system are generally fixed at the outset of the project. This upfront investment in infrastructure sets one of the key elements of the Life of Project T&S Cost for the entire lifespan of the project. Following normal practices to calculate the tariff emitters pay for this service, project Capex is then spread/recovered over the lifespan of the system and linked to volume of CO_2 stored or expected to be stored. Within a range, the Capex is not heavily influenced by the design life, or the utilization of the system. The effect that the fixed nature of upfront capital investment has on Life of Project T&S Costs is manifest in two significant ways, as discussed below.

Project Life Span

Project life span is a key variable in the business case of any T&S system. If a system can operate for longer and the capacity is utilized over the full lifecycle period, the life of T&S project capex per tonne of CO_2 stored is lower. To illustrate this concept, a very simple calculation, which does not consider Capex, Opex, depreciation or financing costs is shown in the table below.

	15 YEAR LIFE	20 YEAR LIFE	25 YEAR LIFE
System Capacity	5 MTPA	5 MTPA	5 MTPA
Capex Cost (Nominal project estimate)	£ 1.5bn	£ 1.5bn	£ 1.5bn
Life of Project Capacity Utilization	80%	80%	80%
CO_2 Stored per year	4 MTPA	4 MTPA	4 MTPA
CO_2 Stored over project life span	60 MT	80 MT	100 MT
Capex cost per tonne of CO_2 stored	£25/t	£18.75/t	£15/t

Table 8.1 - Simple example of the impact of extending the life of a T&S system

Table 8.1 shows that the Capex cost per tonne of CO_2 decreases in proportion to the system's lifespan, if market conditions, availability of emissions to store and storage volumes allow.

Clearly, several factors will influence the ability to simply extend the life of a T&S system including the availability and reliability of emissions and the size of store. Incremental Capex is also likely to be required throughout the system life to maintain operations, however, the effect that extending the life of a T&S project has on the Life of Project T&S Costs is dramatic as illustrated by this simplified example.

Capacity Utilization

A linked variable, which also proportionally affects the life of system T&S costs is the utilization of the system capacity over its full life. Drawing on the simple example above, a second calculation which fixes the project life, installed capacity and Capex has been produced (Table 8.2).

	70% UTILIZATION	80% UTILIZATION	90% UTILIZATION
System Capacity	5 MTPA	5 MTPA	5 MTPA
Capex Cost (Nominal project estimate)	£ 1.5bn	£ 1.5bn	£ 1.5bn
Project Life	20 Years	20 Years	20 Years
CO_2 Stored per year	3.5 MTPA	4 MTPA	4.5 MTPA
CO_2 Stored over project life span	70 MT	80 MT	90 MT
Capex cost per tonne of CO_2 stored	£21.4/t	£18.75/t	£16.7/t

Table 8.2 - Simple calculation showing the effects of capacity utilization

Again, this simple example highlights that systems that utilize more of the installed capacity over the life of the project can have lower Life of Project T&S Costs.

Maximizing system capacity utilization, particularly over an extended period is a challenge for this type of infrastructure and as above, it is accepted that this is not a simple variable to optimize. Factors outside of the control of the developers such as changes in government policy, emitter reliability and general macroeconomics of the emitter base can affect the availability of emissions. Other factors that are more in control of the developers, such as initial system installed capacity, system reliability, and store management can also constrain the amount of CO_2 stored. Causes of poor utilization of capacity aside, it is clear that lower utilization over the lifespan of the project can have dramatic effects on the Life of Project T&S Costs.

Volumes Transported and Stored for Capital Outlay

Changes in system life span and utilization both ultimately affect the volume of CO_2 stored by a T&S system but do not play a significant role in the Capex required to construct the system. These are obvious concepts that are consistent with most infrastructure projects, and they will affect all T&S systems in different ways. Given the importance these factors play in the life of T&S project costs they have been highlighted in this report.

8.2.3 Types of Emitters and System Utilization

Cluster type CCS projects, where multiple emitters are connected to a T&S system are being developed in several regions. The mix of emitters that are connected to the T&S system varies from cluster to cluster, but they can be grouped into categories that impact the cost of building and operating the system. The potential impact on the system's utilization is described below:

- Base load emitters: These types of emitters produce a steady and consistent flow of CO_2 with only small variations in flow from hour to hour. The emitters, typically manufacturing, petrochemicals or industrial emitters that produce commodity products, will target a very high and consistent throughput of their plant to maximize revenue for their core business. For example, ethylene crackers or refinery businesses will aim to be online, producing at 100% of their capacity for more than 97% of the year. This approach produces a high and consistent flow of CO_2 to the T&S system.
- Intermittent emitters – Intermittent emitters produce a variable flow of CO_2 with both in-day variations of up to 100% capacity routinely expected as well as strong seasonal variations in flow, with months of operation at maximum capacity followed by months of much lower or no flow. Intermittent emitters are typically power generation assets or industrial processes that run in a semi batch type production mode. For example, a typical gas fired power plant in a country with significant renewables penetration in the grid might expect to output at higher capacity when wind or solar generation is at lower outputs, with the converse when wind or solar generation is at higher outputs. This effect is particularly pronounced in systems that only have emitters connected by pipelines and do not have the ability to smooth out fluctuations using liquid emitters.

The combined effect that the intermittent emitters have on a system is highlighted in Figure 8.2. For the purposes of demonstrating the effect, the chart is produced for a CCS network with three types of emitters:

- Industrial user A – 1MTPA capacity base load:
    - A petrochemicals user with high uptime and high T&S system utilization and low fluctuation in flows delivered to the system across the year.
- Industrial user B – 1 MTPA capacity base load:
    - A cement production plant with high uptime and high T&S system utilization and low fluctuation in flows delivered to the system across the year.
- A dispatchable gas fired power plant - 2 MTPA intermittent user:
    - A gas fired power plant that is subject to variations in output on a daily basis, day and night, summer and winter and also affected by intermittent renewables generation from wind and solar.

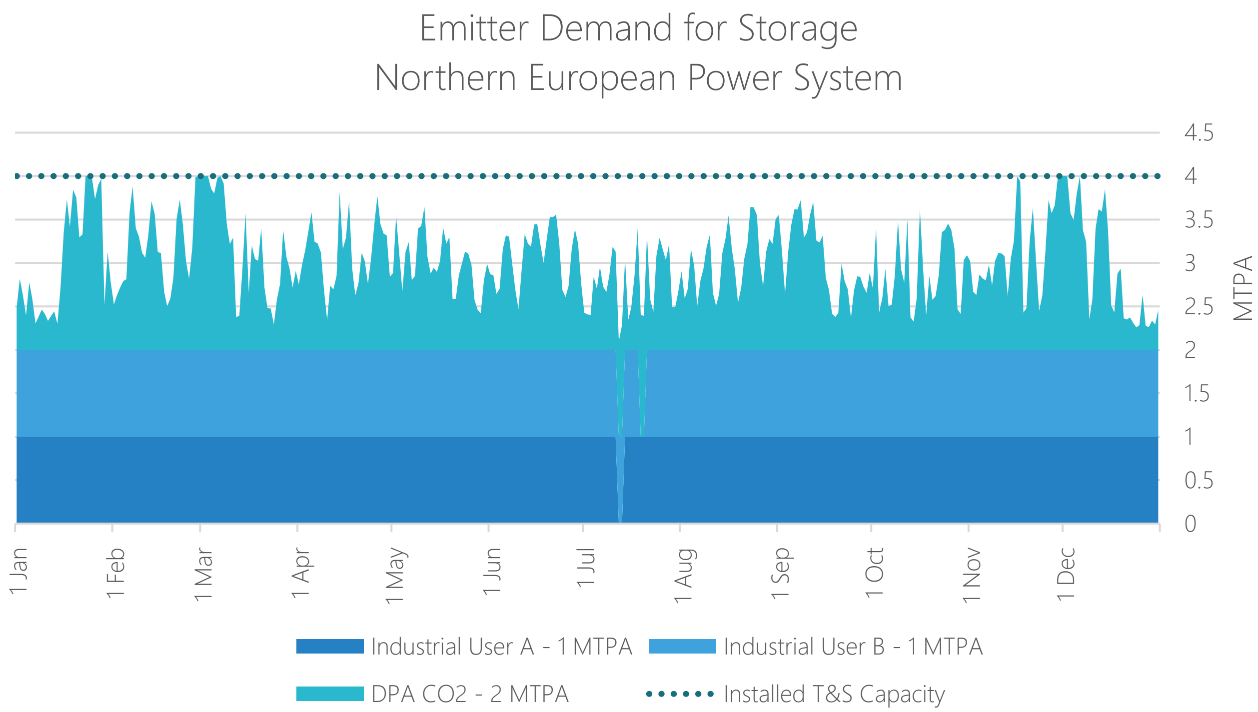

Figure 8.2 - The effect of intermittent emitters on life of the system

It has been assumed that the capacity of the system has been set to allow all emitters to flow at their maximum capacity, i.e. 1+1+2 MTPA but because of the intermittent nature of the dispatchable power user, the actual peak capacity is used only when gas power plant output is high, typically when renewables output is low. This type of T&S system throughput profile is typical for systems with dispatchable power emitters and can be seen across the year but also within each day. The profile has been generated using UK Electricity grid data (NESO, 2024) and is representative of the problem of a system that has centrally dispatched gas fired power plants connected to a large power grid with significant renewables generation capacity.

For a system with this mix of emitters, the T&S system would normally be designed for a peak capacity of 4MTPA, to ensure that all emitters can store CO_2 when they require the service and the costs of building the system are based on the peak capacity. However, when the actual volumes stored are compared to the peak capacity, effectively the white area in the chart, the average volume of CO_2 stored by a 4 MTPA system is reduced.

For the example shown above, where the gas power plant counters low renewable generation periods in the UK, the utilization of 4 MTPA capacity used across the year may be circa 3MTPA, assuming a renewable power generation load factor of circa 50%. This effect, where a 4MTPA system has been built but only is 3MTPA is stored pushes up the unit cost of the T&S system. Choices made during the design of a pipeline only system can help to smooth out some variations in flow, by using the pipeline to store and then release volumes of CO_2 by increasing/decreasing the operational pressure of the pipeline, known as line pack. However, the use of line pack to mitigate large changes in flowrate can be limited, especially in systems where changes in pressure make relatively little impact on the density of the CO_2 in the pipeline (e.g. systems designed to transport CO_2 as a dense phase gas). Large pressure swings in such systems, particularly pressure reductions, can introduce operational issues by evolving liquid and gas in the pipeline, moving the system to operate in "multiphase", which it may not be designed to manage. The number and the operation of the wells for this type of system are also affected by the requirement for intermittent flows which again, can add significant Capex.

This effect has been recognised within the Dutch SDE++ subsidy framework for CCS because of the mix of emitters on the proposed systems. An extract from the "2024 SDE++ Final Advice Basic Amounts" document, the publication which details the levels of subsidy an emitter can claim is shown below (Table 8.3). The extract is for variant 1A, a post combustion emitter that can operate for 8,000 hours or 4,000 hours per year.

PARAMETER	SDE++ 2024 VARIANT 1 A	SDE++ 2024 VARIANT 1 A
Emitter Type	Baseload	Intermittent
T&S System Type	Gaseous Transport	Gaseous Transport
Number of Operating Hours	8000 h/year	4000 h/year
T&S Fee Allowance	€71.8/t	€143.6/t

Table 8.3 - Comparison of allowances in the SDE++ scheme between baseload and intermittent emitters (PBL Planbureau voor de Leefomgeving, 2023)

The inclusion of intermittent emitters and the seasonal profile resulting from their involvement in a network will vary from country to country and by region, but the impact of how intermittent emitters (particularly gas fired electricity generators) use CCS T&S systems is significant and needs consideration within the business case during the planning phase of a project. This element is rarely discussed in the cost data found during this analysis with the SDE++ allowance data referenced above the only location where it is mentioned.

8.2.4 Pipeline System Future Expansion and Early Operations Utilization

Pipeline T&S systems are similar to most pipeline systems where the cost of adding incremental capacity during the design phase is relatively low if it is considered early in the project life. Figure 8.3, taken from the UK Government's Infrastructure and Project Authority Cost Estimating Guidance, helps to display the profile of influence on value and project costs, with decisions made early in a project life creating high levels of value, at a low cost.

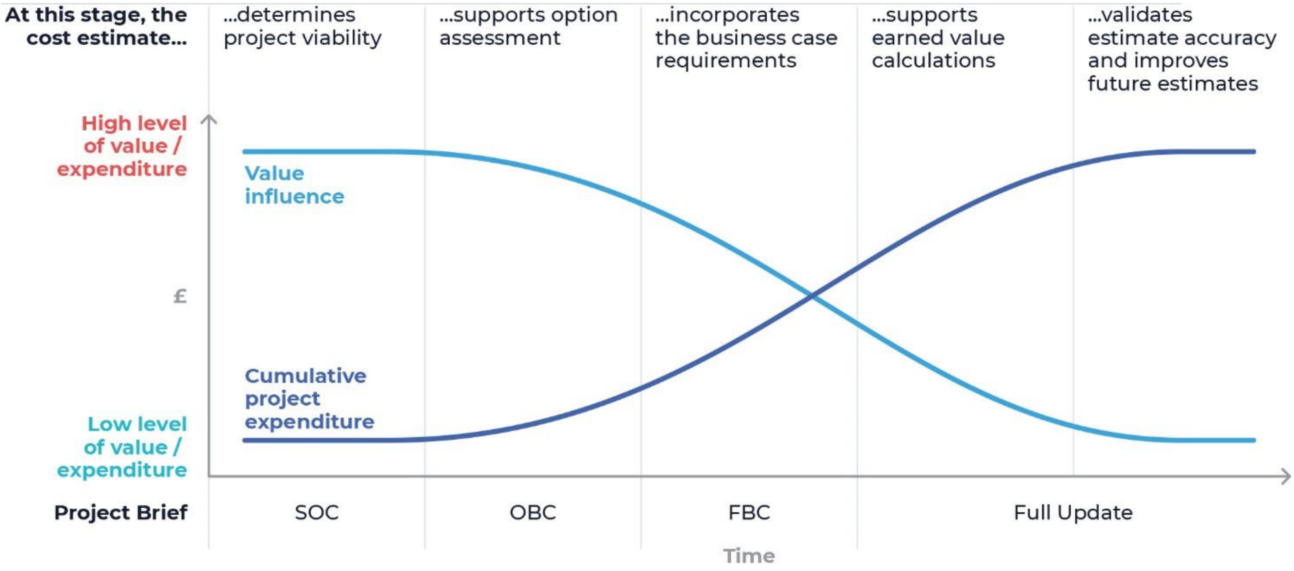

Figure 8.3 - Relationship between value influence, project expenditure and time from UK IPA (Infrastructure and Projects Authority, 2021)

Examples of options for developers include:

1. Installing a higher capacity pipeline than required to service the initial emitters of the system.
2. Installing higher capacity compressors or pumps than required for the initial emitters of the system or building some of the supporting infrastructure, foundations or grid connection capacity, for example, to allow additional compressors to be added later.
3. Drilling more wells than needed for the initial emitters of the system or installing subsea infrastructure to enable further wells to be easily added to the system later.

The cost of increasing the maximum system capacity if additional pipelines need to be installed is typically much higher and the tension between investing in pipeline capacity ahead of demand versus building additional capacity later, is a common dilemma for system planners. These options are available for system planners on single user developments as well as the increasingly common cluster developments being discussed.

To try and highlight this effect for a pipeline system, Xodus estimation tools have been used to produce order of magnitude Capex estimates for a subsea pipeline system that intially has 5MTPA peak pipeline capacity demand which rises to 10 MTPA after 10 years. To meet this demand a 10 MTPA pipeline could be installed or one 5 MTPA pipeline installed initially with a second pipeline installed when the emitter demand materialiases 10 years later. Table 8.4 estimates the cost of installing a single 10MTPA pipeline intially or taking an incremental approach by installing two smaller 5 MTPA pipelines 10 years apart.

PIPELINE CAPACITY	PIPELINE DIAMTER	PIPELINE LENGTH	PHASE	ESTIMATE ACCURACY	INDICATIVE TOTAL INSTALLED COST	CAPEX COST PER TONNE OF CO_2 TRANSPORTED
10MTPA Capacity	26"	200km	High Density Liquid	More than +/-50%	£720million	£72 Capex /MTPA
5MTPA Then 5MTPA	One 20" Then One 20"	200km	High Desnity Liquid	More than +/-50%	£620million Then £620million Pipelines installed 10 years apart so limited project cost efficiencies.	£124 Capex /MTPA

Table 8.4 - Order of magnitude costs for a range of pipelines

The results of the order of magnitude estimates highlight the cost efficiencies inherent in installing larger capacity pipelines from the project outset, when compared to installing parallel pipelines to meet demand over time. The estimate however also highlights that the installed cost of the larger diameter pipeline is circa 15% higher in this case. This is a cost that needs to be paid for over the operational life of the system by the system emitters.

The potential to build relatively low-cost, incremental capacity early in a project life is an attractive proposition but should be set against the risk of building an underutilized system. This is particularly challenging for T&S systems due to the relatively nascent nature of the market and due to the cost of investing ahead of demand typically falling on already high cost elements of the system, such as pipeline or ship costs. This will escalate the problem if the demand for the service does not materialise. If the full project capacity is not met through utilization, this will result in a higher cost per tonne stored than initially forecast. To help highlight the problem, Figure 8.4 has been produced based on the capacity utlization of a notional 15MTPA T&S hub over the lifetime of the project. It assumes that the hub has been sized to cater for the emissions in a region but the capture capacity is established over time, constrained by construction activities, the local carbon price and the number of emitter projects attempting to join the hub. Later in the project life, some of the emitter projects will leave the system due to changes in their core market and the electrification of energy intensive processes.

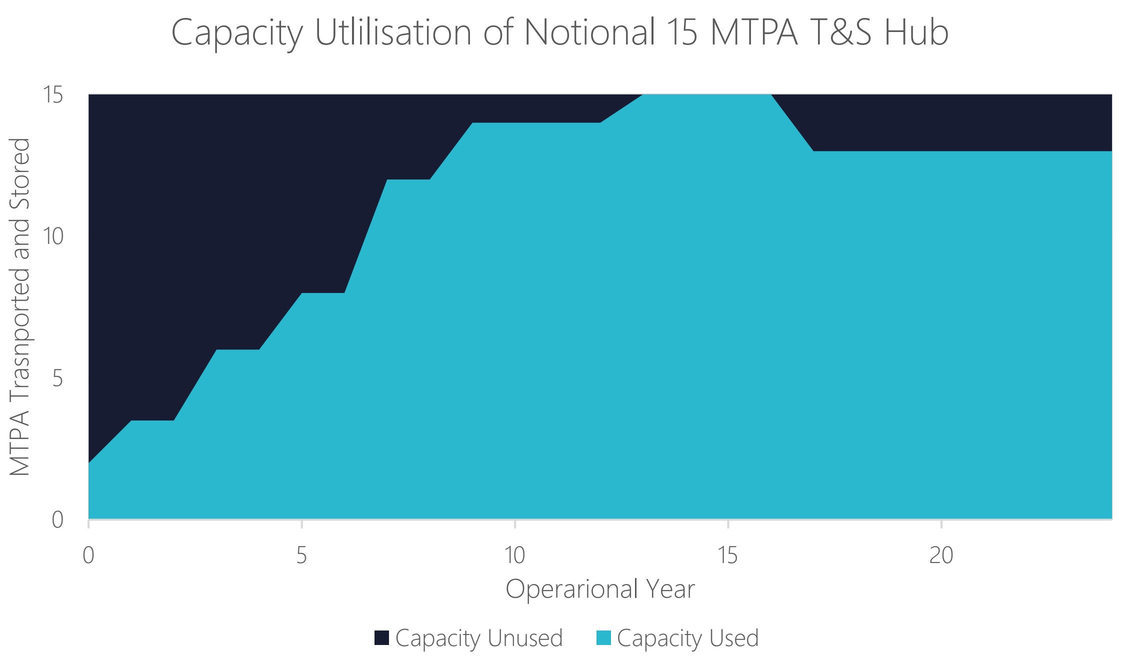

Figure 8.4 - Capacity utilization of notional 15 MTPA T&S hub

The lifetime utilization of the system in this example is 74%, i.e. on average across the life of the project, 11MTPA is used, out of the available 15MTPA. With the Capex fixed, the Life of Project T&S Costs will be based on 11MTPA and not 15MTPA, pushing the cost per tonne stored higher. Revenue flows and the time value of money will compound the effect of lower utilization in early life.

It is noted that this is a difficult issue to address and there is very unlikely to be a "perfect" solution to the problem. The potential for costs to escalate, particularly if demand does not materialise, does however highlight that this should be an area for focus for stakeholders.

8.2.5 Cost of Shipped Liquid Transport

Currently, liquid CO_2 carriers are relatively small, in the region of 1,200-1,800m^3 and used within the food industry. However, the Northern Lights project has constructed 2 carriers of 7,500 m^3 capacity each, with 2 additional carriers planned. As the market for CO_2 storage grows and remote emitters require carbon removal, it is anticipated that the size of these carriers will increase to accommodate larger volumes of CO_2 transport. Some conceptual developments forecast having carriers up to 50,000m^3 and higher (CCSA & ZEP, 2024).

A recent market study carried out by Clarksons, a shipbroker, on behalf of the CCSA provided insight on the potential cost of transportation of liquefied CO_2 by ship, given current market conditions for vessel construction costs and operating costs (Clarksons, 2024). The report focused on selected routes within northwest Europe, and the routes are broadly representative of projects currently under consideration. Clarksons detailed some of the individual cost elements required to calculate the freight rates for shipping by sea, presented in US$/tonne and converted to £/tonne for the purposes of consistency in this report (Figure 8.5). Many factors influence the freight rate including daily hire rate; distance; vessel speed; cargo size; fuel price and port costs to name a few. Clarksons notes that port costs in particular have the potential to be high in Northwest Europe and while they are currently unknown for CO_2 cargoes, it is possible they will have a significant impact on freight rates, particularly for shorter routes.

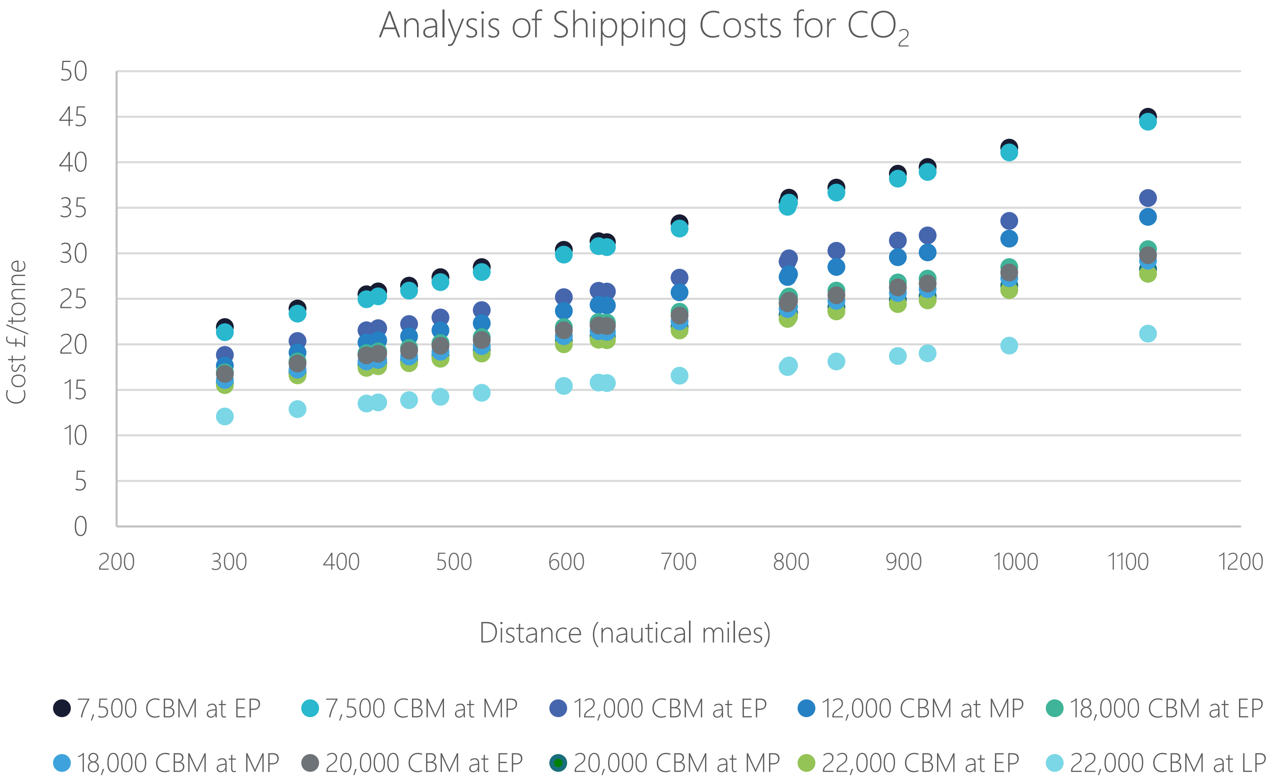

Figure 8.5 - Spread of shipping costs (Clarksons, 2024)

On analysis of all shipping routes within the Clarksons report, the data demonstrates that larger vessels, at lower pressures, travelling over shorter distances incur lower costs compared to smaller vessels, travelling longer distances at elevated pressures. The range of freight costs in the report is from £12/t to £45/t, but it should be recognised that, if any of the assumptions change, the freight costs will change. The port costs for each of the vessel sizes were provided by Clarksons, but no variation in costs associated with individual ports was assumed.

In addition to the expected shipping costs, there will be other infrastructure costs associated with shipping CO_2. Loading CO_2 for transport, will necessitate a jetty or transfer system of adequate size to accommodate the ship. Given this is an emerging industry, either upgrading/retrofitting jetties or construction of new jetties will be required and will incur a significant cost.

A pre-FEED study conducted by Ervia in 2022 and funded by an EU programme, outlined Class 4 cost estimates for two liquefaction terminals in Ireland (UKCCSRC/Ervia, 2022). As demonstrated in Table 8.5, there can be a significant difference in Capex/MTPA between two sites located in the same country. The Capex for the Cork project is over 50% higher per tonne of processing capacity than that of the Dublin project highlighting the role that project/location specific factors can have on this part of a transport system.

DESCRIPTION	CORK	DUBLIN
Plant Capacity	1.25MTPA	1.75MTPA
Capex	€510m	€450m
Capex/MT (25 years)	€16.3m	€10.3m

Table 8.5 - Ervia Capex costs (UKCCSRC/Ervia, 2022)

Reviewing the Capex breakdown of the Ervia project shows there is significant variation in the high-cost elements like liquefaction, CO_2 storage and jetty arms (Table 8.6). This difference in costs is partly due to different requirements and partly due to the fundamental differences between each site. For example, the intermediate storage volume for Dublin is 14% greater than that of Cork, although the Capex difference is only 8%. The variation in cost of the project elements highlight the location specific factors that could influence the cost of constructing and operating this part of a transport system.

ELEMENT	CORK (CAPEX %)	DUBLIN (CAPEX %)
Pipelines	6%	2%
Liquefaction	25%	35%
Vents	2%	3%
Storage	23%	29%
Jetty and Loading arms	28%	18%
Buildings	3%	3%
Roads &Fences	2%	2%
Plant Utilities	7%	8%
Regassification	4%	0%

Table 8.6 - Ervia projects Capex breakdown

When considering the cost of shipping CO_2, it is important to consider the whole value chain including liquefaction, intermediate storage, transfer as well as the shipping element. Within each of the individual elements there are a significant number of variables, all of which influence the T&S life of project costs. The relative impact that these variables have on shipping costs would not be expected to dramatically change from region to region although the absolute cost will vary, as it does for other shipped gases.

Given the wide range of costs reported in the literature, there is a significant risk associated with using simple benchmarks for this type of transport method unless key project specific variables are considered.

8.3 Storage System Key Insights

8.3.1 Reservoir Storage Potential and Well Count

The key cost drivers for reservoir storage potential can be split into costs associated with the site characterization phase (appraisal) and those incurred during store operation (during and after injection).

The appraisal phase of a store is crucial for understanding storage potential and economics. Sufficient information from sources like seismic data, injection tests, or historical production data (for depleted hydrocarbon fields) help to build confidence in storage capacity and injection rates over the lifespan of the project.

Optimising storage costs is linked to selecting the best store for the expected volume from emitters, considering both the store and transport costs. The key elements to consider when appraising possible stores are noted below:

1. Size of the store: Ideally, a store should be large enough to accommodate the total CO_2 volume generated by the emitters over the project's design life (typically 20 to 25 years). This allows the cost of transport infrastructure to be recovered over the project life with minimal additional Capex, reducing overall costs. Conversely, if the store's capacity is smaller than the total volume over the transport infrastructure's design life, multiple stores will be needed. Developing multiple stores and potentially extending transport infrastructure will increase Capex and Life of Project T&S Cost.

2. The number of wells needed: The rate of CO_2 that can be injected by each well into a reservoir is site specific and the result of a combination of many different factors that need to be evaluated during appraisal. Additional wells may also be needed to monitor the store as injection progresses.

3. Associated field pressure management facilities: The potential requirement for saline water production wells and associated treatment systems to manage reservoir pressure, is a further cost driver. These costs can be very significant, and they can limit the economic storage potential of a reservoir, despite the technical storage potential initially appearing to be much larger.

It is important to consider all factors when selecting the store for a project and complete the required economic analysis for the full life of the facilities. Smaller stores will have a shorter operational lifespan than larger stores for a fixed injection rate and the operational life may be shorter than the typical design life of the associated infrastructure. In this case, because the store is limiting the useful life of the associated pipeline and/or shipping infrastructure, the cost per unit of carbon stored is higher for a small store than for a larger one, effectively an economy of scale.

8.3.2 Historical Well Integrity and Implications for the Store

When considering potential storage locations, the integrity of the proposed storage location needs to be reviewed in detail to assess the risk of injected CO_2 being released in an unplanned fashion. The reviews consider a large range of potential release mechanisms including natural causes such as routes to other reservoirs, type of rock above the store, fault lines but also must consider the influence that existing wells have on the integrity of the store.

In mature hydrocarbon basins, where exploration and production activities are well established, it is likely that a number of wells have been drilled in and around the storage site. If a depleted hydrocarbon reservoir is being proposed for use as a CO_2 store, it likely means that the existing wells have been plugged and abandoned during the previous operating life of the field. Exploration wells can also be present even if the reservoir was not previously charged with hydrocarbons. This issue can also occur in saline aquifers where wells may have been drilled.

These wells, known as legacy wells (Arbad, Watson, & Heinze, 2022), create potential leak paths for CO_2 and need to be considered as part of the store risk assessment. If the risk of CO_2 leaking from legacy wells, potentially due to the type of cement used to plug the wells not being compatible with CO_2 or if the plugs have been set at the wrong depth, then there could be additional costs associated with making the well safe. Given the large number of wells present in some areas, this is a significant potential cost.

The make safe costs for legacy wells can include re-entering the well and/or drilling new wells to make leaking wells safe and these costs can be broadly equivalent to the cost of drilling a new well. In mature basins, this is not an insignificant risk because of the number of wells already drilled. To help demonstrate the issue, the figure below has been generated using a mapping tool from the UK storage regulator, the NSTA.

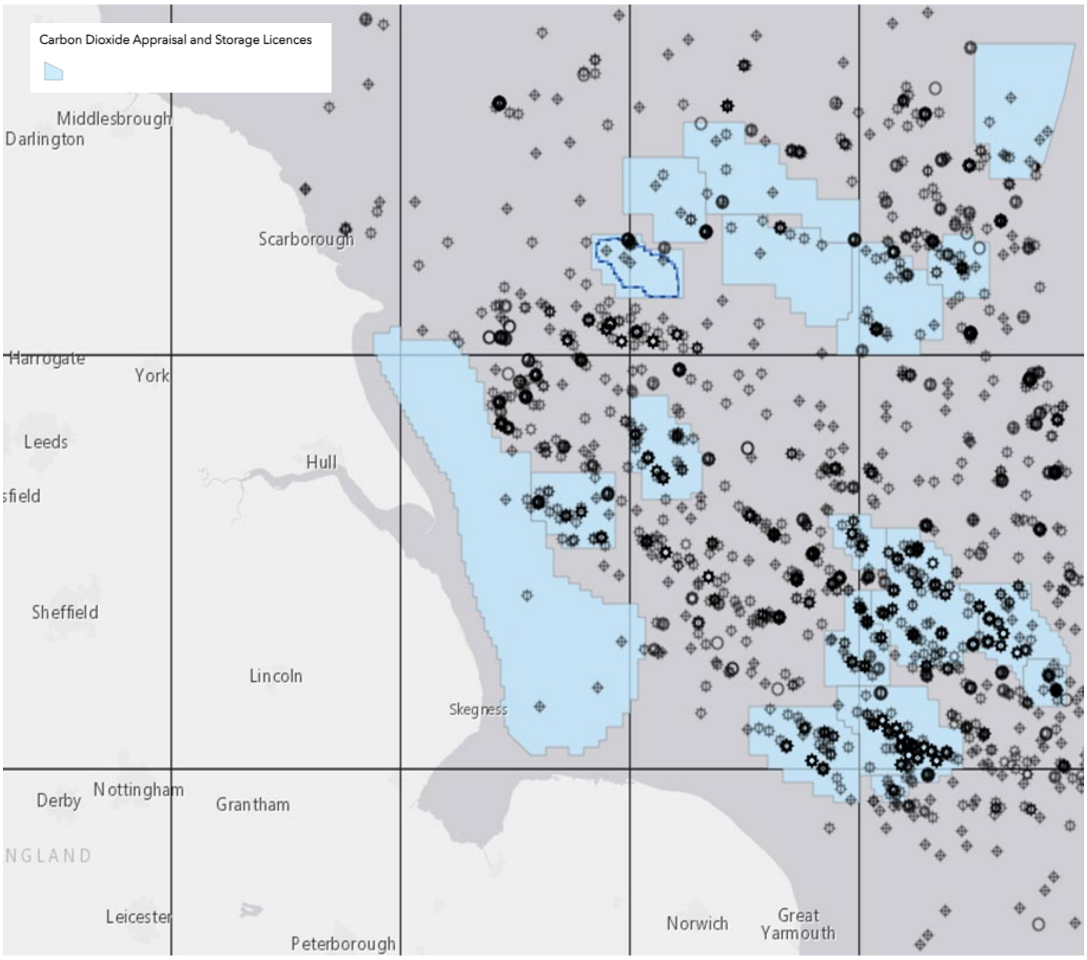

Figure 8.6 - Mapping of wells within the UK Southern North Sea region (NSTA, 2024)

Carbon storage licences currently awarded in the Southern North Sea region are highlighted in blue with existing production and exploration wells marked in black. As shown in Figure 8.7, there are a large number of legacy wells drilled in and around the storage licences in the mature Southern North Sea basin. Any wells that are within a storage site boundary will need to be reviewed as part of the development of the proposed stores and given the age of some of the wells, some may require more detailed reviews or potentially interventions to address the risk of leakage of CO_2.

The issues that legacy wells may pose for a storage project depend on factors such as location, well depth, and well type. Not all storage sites have this issue, but the figure illustrates the challenge of assessing and managing the risks associated with legacy wells.

Where legacy well risks result in the need for physical remediation of some kind, the cost of developing the store can escalate. If a rig is required to remediate an additional well to allow the store to be developed for CO_2 storage alongside drilling 4 new injection wells for the actual store, then the total well count for the store would effectively be 5 instead of 4 and the costs would increase in line with this. The rig costs associated with this notional development could be 20-25% higher than that for the initially planned injection wells but this would not have been known until the storage risk review was completed.

It is clear from the data presented, and the logical build-up of the problem noted, that legacy wells can have a material impact on the rig time needed to develop a store, but this effect will be region, store, and licence specific. For some projects, where the store costs are significant, this issue can cause inaccuracies in the overall Capex estimate.

8.3.3 CO_2 Specification, Impurities and Store Operation

CO_2 captured from various emitters and technologies will contain different impurities. For instance, CO_2 captured from hydrogen production plants may have higher levels of hydrogen compared to CO_2 captured from gas power plants, which may have elevated levels of nitrogen oxides. The concentration of these impurities varies and can affect the operation of the store in multiple ways, including (JIP Participants and Wood Group UK Ltd, 2024):

- Creating reactions that form solids leading to pore plugging impacting injectivity and capacity.
- Changing the physical properties of the CO_2 stream including density and viscosity, which can change the expected injectivity and capacity.
- Introducing solids that occupy pore space.

If the range of likely impurities are understood during the design phase of a system, provisions to manage these impurities can be integrated into the design of the transport system and even, in some instances, the wells. The effect of these impurities will vary based on specific reservoir properties and conditions, and the associated risks will also depend on their concentration in the CO_2 stream.

The challenge of managing impurities once they have entered the reservoir does however dictate that consideration must be given to reducing or removing the impurities before the stream enters the reservoir. The alternative is to control impurities by building redundant capacity into the storage system, such as additional wells or higher capacity wells to allow issues caused by the impurities to be resolved, if this is possible without impacting the nameplate capacity of the system.

Reducing or removing impurities from the CO_2 stream before injection will normally require Capex and Opex to be spent as would providing additional well capacity to resolve issues created by impurities. Because of the requirement for additional Capex or Opex to resolve the issue, there is a natural tension between users of the system that are generating the impurities and the storage operator to control the impurities. Ultimately, the impact of impurities on reducing storage injectivity or capacity can affect all system stakeholders, but the cost of either reducing or remediating the consequences can fall on different parties resulting in differing costs being allocated to either the capture or T&S elements of the value chain.

The impact of impurities on the operation of a T&S system is complex and project specific, potentially affecting the T&S developer Capex/Opex profile and ultimately the tariff. This item needs careful consideration and management to avoid impurities significantly contributing to the tariff or in the worst case, permanently impacting the capacity of the T&S system.

8.3.4 Store Pressure, Flow Assurance and Opex Considerations

The design of a CCS T&S system has a small number of firm elements that influence the design of the system. The location of the emitters and store is one example, where these elements have a strong impact on the length and routing of the pipeline. A second important element is the initial pressure of the store, and this will dictate the types of facilities that are needed to condition the CO_2 for injection or the types of wells that are installed.

Injecting CO_2 into depleted hydrocarbon fields is a key cost driver in storage projects. These fields, once gas or oil reservoirs, had high initial pressures that dropped as hydrocarbon production progressed. Production usually halts when the extraction rate no longer covers operational costs, leaving reservoir pressure very low, often below 40barg.

CO_2 transport pipelines will typically operate at pressures of 100 barg or more to reduce pipeline Capex costs as discussed in this report. When using a depleted hydrocarbon field for CO_2 storage, it is crucial to manage the pressure difference between the CO_2 pipeline and the reservoir over the life of the store. Managing the pressure may require heaters, well workovers, or equipment changes at the injection location and the requirement will change over time as the store pressure increases.

The additional equipment required to manage the pressure difference between a pipeline operating at typical pressures of 100 barg or more and a depleted hydrocarbon reservoir can be significant, particularly if heating is required. The relationship between the emitter location, length of pipeline, available fields and the total cost of storage is complex but understanding the options, and the long-term operating cost of depleted hydrocarbon fields is important from the outset as it can drive the requirement to install costly additional equipment to manage the pressure profile of the field.

8.3.5 Cost of Monitoring and Assurance of the Store

The regulations associated with monitoring of CO_2 once it has been injected in the reservoir vary from region to region with a higher number of operational projects in North America using their country specific frameworks than is currently the case in Europe, for example. Specific regulations are discussed in detail in other publications (Frattini, Becattini, & Mazzotti, 2024) and (U.S. Environmental Protection Agency, 2010), but the concept of monitoring the CO_2 injected is to help prove that the reservoir is performing as planned during the operational life of the store and that the CO_2 will remain in the store for an extended period of time, i.e. completely and permanently stored (European Union, 2015). They also aim to prevent associated negative environmental and societal impacts. The technologies and techniques that are used by developers to satisfy the regulations should be described in a site-specific measurement, monitoring, and verification (MMV) plan, which starts to be assembled during appraisal stage of a CCS project and is finalized prior to construction.

The cost of demonstrating that the store is performing as expected during operation and that the CO_2 will be permanently stored varies from region to region, with local regulators applying the text of global conventions such as the 1996 London Protocol and OSPAR in similar but different ways. In some regions, the local or provincial regulations are still being developed based on national agreements. In general, the requirements, using the European directive which has been written considering international risk management frameworks as an example, are as follows:

1. Baseline – Understand the status of the reservoir and wider storage site before injection begins and produce a storage plan and dynamic models that simulate migration of the injected CO_2 and associated impacts over the total life of the store, including post injection.
2. Monitoring during operation – Tracking of the injected CO_2 in the reservoir using direct or indirect methods and demonstrating that the store is performing as predicted by the models and that there are no unexpected events (United States Environmental Protection Agency, n.d.).
3. Post closure monitoring – Continuing to monitor the store to track the location of the CO_2, identify any seabed deformations or localised CO_2 increases until it can be demonstrated that the risk of the CO_2 being released is acceptably low. The time needed post injection to satisfy this requirement varies depending on risk and is country specific but in Europe this period is no shorter than 20 years.

This approach is also generally followed in North America with regional administrations beginning to develop more detailed guidance based on national frameworks.

From a technical perspective, the approaches taken, and the frequency and the duration of monitoring activities will vary from store to store. For example, stores using depleted hydrocarbon reservoirs will have much greater insight to the field operation than a saline aquifer store, and depleted hydrocarbon stores may have lower cost activities associated with the baseline measurement task. Conversely, the risk of leakage from a depleted hydrocarbon reservoir may be higher given the presence of existing wells drilled through the reservoir cap rock. Operational challenges during the injection phase of a project may result in higher cost monitoring activities than expected, and the extent and cost of monitoring will be dependent on performance during operation.

The costs associated with monitoring the store throughout its life are known to be significant, largely driven by the cost of seismic surveys rather than well monitoring or environmental surveys, with the spend spread over decades. The actual cost of the monitoring activities are however country and store specific, and this variation should be considered when estimating the cost of these activities in any overall system cost estimate.

9 TASK 4 - RECOMMENDATIONS AND BASIS FOR PHASE II

Following a review of the available sources of information and using knowledge of typical project development processes the following recommendations are made to help address deficiencies in the current T&S cost estimating processes being used by stakeholders.

Many of these tools are already in use by both public and private organizations but typically are not publicly available due to the proprietary nature of the data or methods used. The recommendations for phase II of this project may lead to the development of new tools for IEAGHG members. Alternatively, phase II could invest in existing tools to enhance their underlying dataset or methods, which may be a more efficient way to achieve the same outcome. The decision on how to implement the recommendations will ultimately be made by the IEAGHG, and the following sections should be read with this context in mind.

9.1 Standardised Cost Metric Reporting Framework

It has been necessary to define from the outset of this study what the word "cost" means with two definitions used to describe the cost of storing one tonne of CO_2, one including financing costs and one without. It is also apparent from the data reviewed that the Capex and Opex estimate accuracies are not normally quoted alongside the estimates and finally it can be difficult to understand how system capacity and utilization effects have been incorporated into the reported cost.

To allow stakeholders to understand published costs, it would be helpful if they were reported using a standard framework. This would be useful for Capex and Opex costs to inform the reader about the perceived accuracy of the estimates but is essential when unit costs, either tariffs or life of project costs are reported.

This approach has been taken by the projects supported by the Alberta Government allowing costs to be more easily understood and reported. Developing this approach to encompass projects outside of this jurisdiction would be beneficial as more projects are launched and progress towards FID and operation.

9.2 Standard Project Process and Cost Estimating Guidelines

Cross sector experience has highlighted there can be issues communicating key project details such as the cost estimate accuracies. The variation in definitions and scope across industries associated with key work stages such as Concept Design, FEED and Detail Design can lead to confusion. This, in turn can lead to misunderstandings in project cost estimation and its associated accuracy.

In a market where the volume of projects is planned to increase substantially and where national governments will be required to contribute financially to projects in differing ways, it could be beneficial to all parties to attempt to report project progress or maturity against a common, transparent framework. This should be combined with guidelines on cost estimation and cost estimating accuracy.

This issue is of particular importance for government agencies that may be trying to compare or fund competing low carbon technologies in different sectors. Allowing users of the cost data to understand the maturity of the project and its associated cost estimate is widespread in the private sector. The common approach allows joint venture partners, banks, and other stakeholders to easily understand the status of the project which in turn helps to enable FID decisions to be taken in a structured manner. Developing a common framework for reporting on project maturity that could be used across projects and regimes would assist all stakeholders in understanding the relative maturity and cost of projects in a more transparent manner.

9.3 Consolidated Cost Database

In a nascent industry with few projects, there may be considerable value in creating a peer-reviewed cost database focused on establishing cost ranges for critical components of T&S infrastructure. This database could serve as a benchmarking tool for project developers and government stakeholders and could be set-up relatively quickly to support stakeholders involved in the current surge in planned projects.

While a benchmarking database cannot eliminate the inherent cost uncertainties of a new industry, it would provide a reliable mechanism for stakeholders to have a reliable benchmark to review project costs and compare commercial viability. This cost database would also help reduce the information gap between operators and public stakeholders helping parties to work more constructively together.

As seen in this report, developing cost information is both expensive and commercially sensitive. However, operators could contribute by providing and reviewing cost inputs, such as well or compressor costs, to ensure they are reasonable and up to date.

We believe such a cost database would be highly beneficial for early-stage developers to screen projects and apply for licenses, as well as for public stakeholders when offering licenses and reviewing costs as part of subsidy allocation processes. The Performance Forum (Turner & Townsend, 2016) in the upstream oil and gas sector offers a service similar to this concept and has been in existence for 30 years with many of the same companies involved in the CCS sector participating in the initiative. The Rushmore Reviews (Rushmore Reviews), which focuses on drilling and well costs, is another example of similar benchmarking database for the oil and gas industry. The longevity and membership of these cost benchmarking forums highlights existing precedents of developers sharing cost information and the perceived value of cross company benchmarking data to the participants.

9.4 Emitter Base and System Utilization Mapping Tool

It has been noted in this report that intermittent emitters of T&S systems often require system capacity to be installed but the utilization of the installed capacity, in both the T&S elements of the system is low due to the nature of their business. Similarly, capacity that has been built for unspecified future emitters leading to low T&S capacity utilization early in the project life, could also lead to system underutilization over the project life. The effect that underutilization of capacity has on the cost of storage can be high. As a result, it is important to map and understand the system utilization over the planned project life and compare this to the planned system capacity to ensure that the demand for capacity matches the installed capacity, minimising the Life of Project T&S Cost.

It is noted that this is a difficult task in a developing sector but, given the potential efficiencies associated with operating a system which is appropriately sized for the mix of emissions, a focus should be placed on tackling this difficult task.

The purpose of such a tool would be to consider both in-day variations in flow from emitters, long term trends in flow from industry and the potential to use liquid volumes to help optimise the capacity of varying parts of the system. Similar tools are used for production planning across the process industries as well as for logistics management in most industries to understand constraints in linked processes. Complex CCS systems with a diverse userbase may benefit from adaptation of existing planning tools, particularly during the early development stages of a systems business case to help optimise the capacity and design of the system. It is known that these tools already exist but are not publicly available, notably SINTEF and Brevik Engineering tool developed as part of the CO_2LOS programme highlighting the existing demand for this type of analytical tool.

9.5 Regional T&S Planning Tools

Currently, it is well known that local and national governments are supporting both the construction of individual CCS projects as well as supporting the wider industry through national programmes such as the 45Q Tax Credit for Carbon Sequestration in the US and the Track sequencing process in the UK. The scale of the government support programmes is large and aims to allocate funding in an efficient and fair manner across a wide range of projects.

In some regions, the decision to build decarbonisation hubs or fund single emitter projects requires less planning because the majority of the country or regions emissions are located in close proximity, and the storage options are limited. This is not always the case, and some countries or regions have widely dispersed emitters and multiple storage options that could be configured in a number of ways to transport and store CO_2.

As noted above, there are several variables that can influence the Life of Project T&S Cost, which is ultimately the cost that the government or partners would pay. In an ideal scenario, competition would be used to award funding for CCS projects, with systems that meet the objectives of the government programme, pace of delivery or lifecycle cost etc. being awarded funding.

The complexity of the market in some regions alongside the cost associated with preparing cost estimates for T&S systems to support funding submissions to governments could mean that some opportunities to reduce Life of Project T&S Costs by better matching of emitters and T&S systems are missed. This issue could manifest itself in under or over utilized systems being built because of locational or policy effects.

The development of tools that can consider a very large number of possible system designs, pairing, combining, and matching emitters and stores in a systematic way is a useful method of understanding and ranking the potential projects in a region. Completing a high level but independent view of the potential market can help to identify projects that have inherent advantages through location, easy access to emitter volumes or other important factors and help add to the decision-making process where governments, or other parties have broader control of projects in a region.

It is known that versions of this type of tool already exist, and they are being used by several public and private organisations in the sector to support decision making. The current use of these sorts of tools highlights the demand for this type of analysis. Investing in the existing planning tools to further develop the functionality or accuracy of their output is likely to be a more effective and efficient use of resources if this recommendation is followed.

9.6 Shipping Cost Framework

It has been noted in this report that there is potentially a large market for shipping liquid CO_2 in all three regions. It is also noted that the life of project cost of shipping liquid CO_2 can vary, and the potential range of costs is relatively large. The factors driving the cost of the shipping are well understood given the maturity of the shipping industry, but it is important for all stakeholders to understand these factors and consider them when compiling Life of Project T&S Cost estimates. The costs of the associated infrastructure, including jetties, storage, liquefaction, etc. for the project should also be understood and considered in cost estimates.

There are several tools or services like this available on the market, such as those provided by Clarksons, that model components of CCS chain configurations, including shipping costs. However, like all modelling tools, the accuracy of the output of these tools is dependent on the quality of input data. Given the potential role of liquid shipping in the industry, it is important to use reliable and robust cost estimates for ship transport and associated infrastructure. Focusing on this topic, either by enhancing an existing tool or through a new project that combines existing research, would be beneficial. Developing a detailed framework or tool would help inform early phase project decisions between building a pipeline or using a shipping transport system, where these options are comparable. Furthermore, the framework would aid creating accurate cost estimates for projects once the decision to use shipping as the transport method has been made.

10 CONCLUSIONS

This review confirms the initial premise of the study, that there are limited publicly available sources of recent and useful cost information published. The information that is published shows a wide range which is expected given the different locations and project archetypes in the published data.

An informed user of the published cost information may be able to interpret the data and use it in an appropriate way, at an appropriate time in the project lifecycle to inform decisions being made on projects, policy, or investments. Understanding the technical and commercial aspects of a given project allows the informed user of the data to narrow down the range of costs, albeit from a small data set and reduce the potential for misunderstandings of cost.

However, the published cost information does suffer from a lack of clarity on the underlying assumptions that drive the estimates. This issue is to be expected given the relative complexity of the systems, the confidential nature of some of the important variables, and the general uncertainty of key items such as project lifetime capacity utilization. This issue does significantly increase the risk of inappropriate cost data being used as either a benchmark or to set policy. Even well-informed users of the data may fall foul of this issue because of the complexity of the problem, and it would be unsurprising if mistakes have been made previously where this data has been used.

The issues above can be mitigated by developing a standard reporting framework for costs and by using a standard project process to develop those costs. It is thought that this solution to the problem could be easily implemented in conjunction with stakeholders by combining existing similar processes used extensively in industry and forms one of the key recommendations from our work on the topic. In addition to the standardized reporting metrics and processes, developing a T&S specific cost estimating database for common equipment, in collaboration with developers, could be advantageous. Industry-wide benchmarking databases already exist for oil and gas projects and have been utilized by industry for an extended period. The use of benchmarking databases for Oil and Gas projects suggests that developing a similar resource for CCS projects is both useful and feasible. It is known that developers and existing providers of benchmarking services are already developing CCS specific cost databases and there may be benefits in the IEAGHG members focusing and investing in one of the existing databases for this purpose.

Additional recommendations are provided to help to improve Capex and Opex estimates for individual projects. These tools and frameworks are already in use within industry, indicating a need for the service but may currently have a small user base or draw on a limited dataset. Investing in or combining existing tools could enhance the quality of available tools and improve the accuracy of cost estimates and the associated business cases for early phase projects.

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12 GLOSSARY

45Q Tax Credit: A U.S. federal tax incentive for carbon capture and storage projects.

Capex (Capital Expenditure): Funds used by a company to acquire, upgrade, and maintain physical assets such as property, industrial buildings, or equipment.

CBM: Cubic Capacity measured in Cubic Meters

CCS (Carbon Capture and Storage): A technology used to capture and store CO_2 emissions from industrial processes to prevent them from entering the atmosphere.

CCS: Carbon Capture and Storage

CO_2: Carbon Dioxide

Concept Design: The initial phase of a project where the basic idea and feasibility are explored.

Cost Estimate Accuracies: The degree of precision in predicting the costs associated with a project, reported as a range around a central estimate.

Cryomin - Cryogenic Distillation Technology for High CO_2 Concentrations

Decarbonisation Hubs: Centralized locations where CO_2 emissions from multiple sources are captured and stored.

Depleted Hydrocarbon Fields: Former oil and gas fields repurposed for CO_2 storage.

Detail Design: The phase where the complete specifications and drawings for the construction and operation of the project are developed.

Emitter Base: The sources of CO_2 emissions that need to be captured and stored.

Enhanced Oil Recovery (EOR): Technique using CO_2 to extract more oil from reservoirs.

EOR - Enhanced Oil Recovery

EP: Elevated Pressure, in related to storage tank pressure

FBC: Final Business Case

FEED (Front-End Engineering Design): A detailed engineering phase that defines the technical requirements and costs before project execution.

FEED: Front-End Engineering Design

FID: Final Investment Decision

Gated Development Process: A project management approach where a project is divided into stages separated by gates. At each gate, the continuation of the project is decided based on specific criteria.

HP: High Pressure, in relation to storage tank pressure.

Hydrocarbon Basins: Regions with significant oil and gas deposits.

IEAGHG: International Energy Agency Greenhouse Gas Programme.

Intermediate Storage: Temporary storage solutions in CCS systems.

JSA: Joint Study Agreement

kTPA: Thousand Tonnes Per Annum

Lifecycle Costs: The total cost of owning, operating, and maintaining a project over its entire lifespan.

Line Pack: Storage of gas in pipelines.

LNG: Liquefied Natural Gas

Load Factor: The amount of electricity generation in a given period divided by the maximum that could have been generated if the plant had run at maximum capacity for the whole period

London Protocol: International agreement regulating marine pollution.

LP: Low Pressure, in relation to storage tank pressure.

MMV (Measurement, Monitoring and Verification): Processes to measure and assure volumes of CO_2 geologically stored.

Mineralogical Trapping: CO_2 chemically reacts with minerals to form stable compounds.

MP: Medium Pressure, in relation to storage tank pressure.

MoU: Memorandum of Understanding

MTPA: Million Tonnes Per Annum

NSTA :North Sea Transition Authority (UK)

OBC: Outline Business Case

Opex: Operational Expenditure

OSPAR: Oslo and Paris Conventions for the protection of the marine environment of the North-East Atlantic

Out-Turn Costs: The final costs for the project once construction is complete and the project commissioned.

Residual Trapping: CO_2 trapped in pore spaces of rocks.

Saline Aquifers: Porous rock formations saturated with brine used for CO_2 storage.

SDE++: Stimulation of Sustainable Energy Production and Climate Transition

Solubility Trapping: CO_2 dissolved in brine.

SOC: Strategic Outline Case

Structural Traps: Geological formations that trap CO_2 underground.

Supercritical Phase: CO_2 at a pressure above its critical point

T&S (Transport and Storage): The process of transporting and storing captured carbon dioxide (CO_2) from its source to a storage site.

T&S: Transport and Storage

Track Sequencing Process: A method used in the UK to prioritize and allocate funding for CCS projects.

UKCCSRC: United Kingdom Carbon Capture and Storage Research Council

Utilization Mapping: The process of analysing and planning the use of system capacity to ensure efficient operation.

WACC: Weighted Average Cost of Capital

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